0000088213

Transcript Exhibit(s)

Docket #(s): E-01345A-08-0172

Exhibit # : APS1-APS20, AECC1-AECC2, RUCO1-RUCO4 S1-S9.

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To: Docket Control

Re: APS / Rates – Interim E-01345A-08-0172
Volumes I through V (Concluded)
September 15 through 19, 2008

STATUS OF ORIGINAL EXHIBITS

FILED WITH DOCKET CONTROL
09-22-2008

STAFF

1 through 9

APS

1 through 20

NOTE:
6 – Not Confidential. See transcript Volume II (09-16-2008), Page 357, Line 1.

RUCO

1 through 4

AECC

1 and 2

ORIGINAL EXHIBITS RETURNED TO PARTIES

APS

21	Admission Pending until Friday, September 26, 2008. See transcript Volume V (09-19-2008), Page 1086, Line 20

LATE-FILED EXHIBITS

APS

22 and 23

Copy to:

Lyn Farmer, ALJ
Staff (Janice Alward, Esq.)
APS (Thomas L. Mumaw, Esq.) (with Exhibit 21)
RUCO (Daniel Pozefsky, Esq.)

BEFORE THE ARIZONA CORPORATION COMMISSION

<u>COMMISSIONERS</u>

MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

EXHIBIT
APS-1
ADMITTED

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01345A-08-0172 **AFFIDAVIT OF DONALD E. BRANDT IN SUPPORT OF APS'S MOTION FOR APPROVAL OF INTERIM RATE**

General

1. My name is Donald E. Brandt. I am President and Chief Executive Officer of Arizona Public Service Company ("APS" or "Company") and President and Chief Operating Officer of Pinnacle West Capital Corporation ("Pinnacle West"). I am responsible for all aspects of APS operations, including generation, transmission, distribution, customer service, and for general administrative functions. My business address is 400 North 5th Street, Phoenix, Arizona, 85004.

2. The assertions of fact contained within the Company's Motion for Approval of Interim Rate and Preliminary Order (in the form of an interim base rate surcharge of \$.003987 per kilowatt-hour ("kWh") to be effective upon the expiration of the \$.003987 per kWh 2007 PSA adjustor charge ("2007 PSA Adjustor")) are true and correct to the best of my knowledge and belief.

3. The purpose of this affidavit is to testify, from my personal experience and involvement as the Company's President and Chief Executive Officer, regarding the Company's vision for Arizona's energy future, the financial basis for APS's interim rate relief request, the Company's declining Return on Equity ("ROE") and underearning, Pinnacle West's deteriorating stock performance, the likelihood of adverse actions by the credit rating agencies given the Company's chronically weak financial condition, and the impact on APS and its customers of such actions. I will also discuss the impact of the Company's interim rate proposal on the Company and its customers.

4. As Arizona's largest utility, APS is acutely aware of and firmly committed to its role in shaping Arizona's growing and changing energy future. The Company has a vision of stimulating an energy future for the State that is cleaner, more energy-efficient, more reliable, and more customer-focused than what Arizona has seen historically. For this reason, APS has already begun implementing a series of programs intended to improve customer service and reliability, while setting the stage for technological innovations and other developments that will allow additional customer choice and control over their energy usage.

5. For example, the Company has already achieved one of the highest rates of implementation of full, two-way communication Advanced Metering Infrastructure ("AMI") of any investor-owned utility nationwide, and hopes to have completed its roll-out of AMI for all areas in which such technology is practicable by the end of 2012. In tandem with other "smart grid" improvements to the Company's current capabilities, these meters will allow APS to better serve its customers by offering additional rate choices and, when the technology permits, will provide customers with greater future control over their electricity costs. The Company is also in the process of employing a Distribution Outage Management System – a software program that enables the Company to move from a manual outage management process to a state-of-the-art automated system, setting

the stage for improved outage management as well as a real-time distribution operations system. The Company has also identified and implemented several improvements to its system in tribal territories, which will allow APS to continue its recent trend towards securing higher reliability on Native American lands. In addition, the Company continually strives to upgrade its coal-fired generation plants – beginning with the Cholla Power Plant – such that those plants will meet or exceed all existing and anticipated environmental requirements in the years to come.

6. But all of these benefits require substantial funding – monies in addition to the more traditional expenses that APS must already incur to maintain even its basic electric system in attempt to ensure continued reliability for the Company's current and future customers. These costs cannot be borne – and thus these visionary and important customer-focused programs cannot be funded – by a financially weak utility. Sound long-term financial health for APS ultimately and importantly benefits the Company's customers in the form of comparably lower rates, beneficial customer-focused programs, and sustainable, reliable electric service – fundamental necessities in an age of increasing reliance on and demand for energy.

7. Right now, APS is struggling to maintain even its poor present financial condition. Under the Company's present rates, APS's Funds from Operations to Debt ratio (or "FFO/Debt," a key credit metric, as I later describe) will cross the threshold to non-investment ("junk") grade by the end of next year, quite possibly before the Commission will have issued a decision on APS's general rate application. The Company will thus be left wavering on the brink of junk status with no protection against a credit ratings downgrade during the pendency of the general rate proceedings. As explained at length in my testimony supporting the Company's rate application, a downgrade to junk will have an immediate and acutely adverse effect on the Company and its customers in terms of severely restricted access to financing, dramatically increased financing costs,

and decreased operational flexibility. Once the Company falls from the last rung of the investment grade ladder, to which it now clings, no emergency action from the Commission will be able to reverse those consequences. Instead, it will take years for the Company to regain the financial foothold necessary to climb out of junk and to be financially strong enough to provide Arizona with the basic energy infrastructure that is so vital to our communities, let alone the innovative energy developments that APS envisions undertaking in the years to come. As I will explain herein, I believe that, without interim relief of the type requested in the Company's Motion, it is more than likely that APS will be downgraded to junk status before the Commission issues a decision in the Company's general rate proceeding, resulting in approximately one billion dollars of additional costs over the next ten years that will ultimately be borne by APS customers.

8. If the Commission approves the Company's interim rate request, however, it will improve the Company's financial condition such that APS's FFO/Debt ratio will likely remain in the investment grade range until at least the end of 2009, thus allowing time for the general rate proceedings to resolve and avoiding the threat of a downgrade in the interim. This end cannot be timely achieved through the resolution of the general rate case now on file before the Commission.

9. Significantly, under the Company's proposal, the financial relief resulting from the Company's interim rate request can be achieved with no impact to customer bills compared to what customers are already paying today. In addition, and among other customer advantages that I will describe, the request further benefits customers by reducing by at least 41% the overall bill impact of the Company's general rate request at the time it would be decided and preventing the rate volatility inherent in decreasing customer rates only to increase them again relatively shortly thereafter. The opportunity to provide APS with a much-needed safety cushion against a ratings downgrade during

the pendency of the rate case without increasing customer rates beyond what they are already paying today is one that will be lost if the Commission does not act promptly on the Company's Motion and grant APS the interim relief requested.

Specific Background Facts

10. On March 24, 2008, APS filed a general rate application with this Commission requesting permanent base rate relief, which the Company updated in a revised filing submitted on June 2, 2008 to include a test year ended December 31, 2007 ("Test Year"), as requested by Commission Staff. As updated, the Company's filing requests a permanent net annual revenue increase of $278.2 million, exclusive of the Power Surcharge Adjustor ("PSA") revenues that would simply be reclassified as base revenues under the Company's application.

11. As described at length in that application, APS's general rate request was necessitated by both the extraordinary capital expenditure needs that APS has historically faced and continues to face over the next several years as well as the unfortunate reality that today's rates are significantly below the Company's reasonable costs of operation. This non-discretionary capital spending averages **one billion dollars per year** for the foreseeable future and is caused primarily by the rising costs that the Company must incur to build the infrastructure necessary to meet Arizona's growth and to maintain its existing system – costs that are exacerbated by the unprecedented rise in the price of materials and commodities basic to the electric industry. As the general rate application describes, APS's current rates do not begin to compensate the Company for these costs, which APS must incur to ensure that the Company is able to continue providing reliable electric service to both present and future customers alike. Indeed, from the end of the September 30, 2005 test year used to set the Company's present rates in Decision No. 69663 (June 28, 2007) to May 31, 2008, APS spent approximately $1.7 billion on ACC-jurisdictional

capital projects alone – prudently incurred costs that are not reflected in the Company's retail rates.

12. Pursuant to the Commission's time clock rules, A.A.C. R14-2-103(B)(11), APS requested that the rates approved in its general rate application become effective no later than October 1, 2009. However, given the time the Commission has historically taken to rule on APS rate requests, and understanding the Commission's current staffing shortage and considerable workload, the Company is concerned that the Commission may not issue a decision on APS's general rate case until after that requested date and that any new rates resulting from that order may not take effect before 2010.

13. Because the Company is required (to the extent it is able) to continue high levels of capital spending during this period of regulatory lag with rates that do not compensate it for its cost of service, the Company's financial condition – which is already weak, as I will describe – will continue to deteriorate, and the Company will once again be on the brink of a downgrade to junk credit status as early as next year, before the Commission will likely have ruled on its general rate application.

14. The Company's Motion presents an interim solution to this financial emergency, which the Commission cannot timely rectify through the Company's general rate case application.

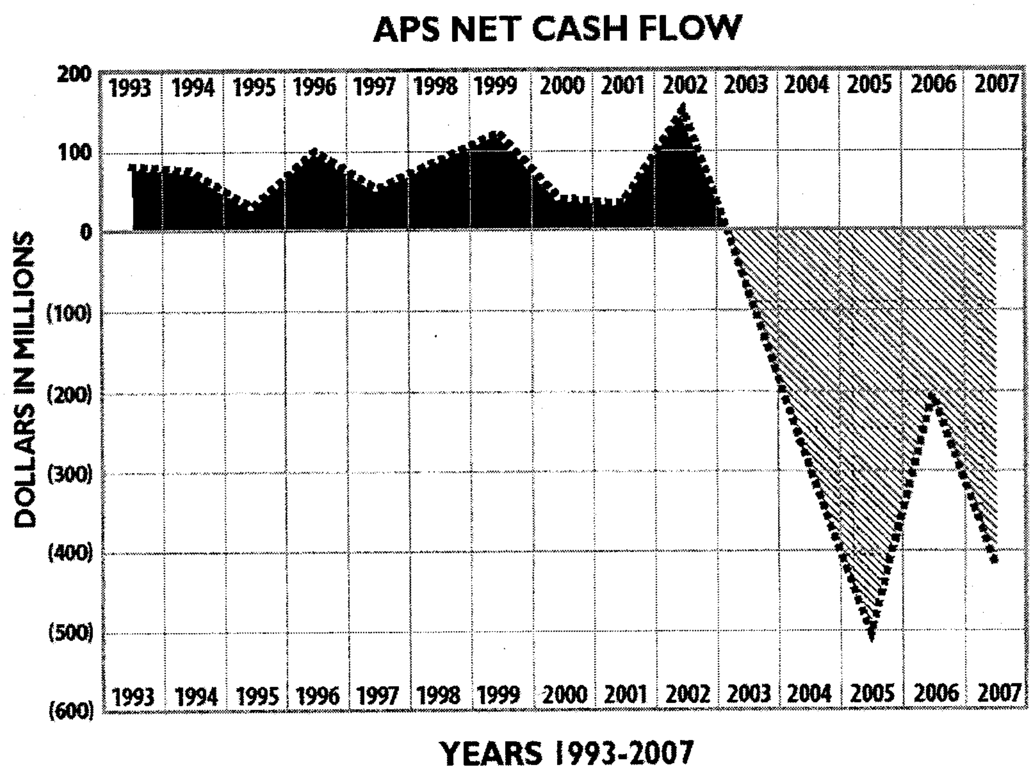
APS's Financial Condition and Credit Ratings

15. The Company's capital expenditure program (consisting of such non-discretionary costs as necessary distribution and transmission lines, generation plant improvements, new environmental control systems, and other service facilities, among other things), together with the Company's need to refinance existing indebtedness as it matures and finance the Company's other capital requirements at the same time, will require the Company to secure over $2 billion of financing from external capital sources over the next five years.

16. The Company's ability to raise these funds depends in large part on its financial vitality – both present and prospective – and the degree to which the financial markets (both debt and equity alike) view APS as an investment-worthy enterprise. However, APS's chronic inability to recover its capital costs has already undermined the Company's financial health and threatens the loss of its financial integrity in the near term without interim relief.

17. APS's financial condition is currently among the weakest of its peers, and continues to decline. In 2007, APS earned an ACC-jurisdictional ROE of only 9.0% (0.4% of which resulted from the impact of unanticipated revenue received during an abnormally hot summer), 175 basis points below its authorized ROE of 10.75%. In 2007 alone, even with unusually hot weather bringing in unexpected additional revenue, the Company's earnings shortfall increased by $67 million, bringing the Total Company earnings shortfall to $321 million over the past five years. Under the Company's present rates, APS's ACC-jurisdictional ROE falls to 8.4% in 2008, to 6.3% in 2009 and to 5.4% in 2010 (just *half* of what APS was authorized to earn in Decision No. 69663). Between the end of the calendar 2007 Test Year and year-end 2010, the Company will have lost another **$384 million** in authorized earnings looking only at those items within the Commission's jurisdiction – a striking level of underearning caused by factors entirely outside of the Company's control.

18. Another measure of a company's financial health is to look at its net cash flow, after accounting for capital expenditures and financing costs, by comparing the company's cash receipts to its cash payments over a certain period. By this measure, too, APS's financial vitality has weakened considerably over just the past five years, as the following graph shows.

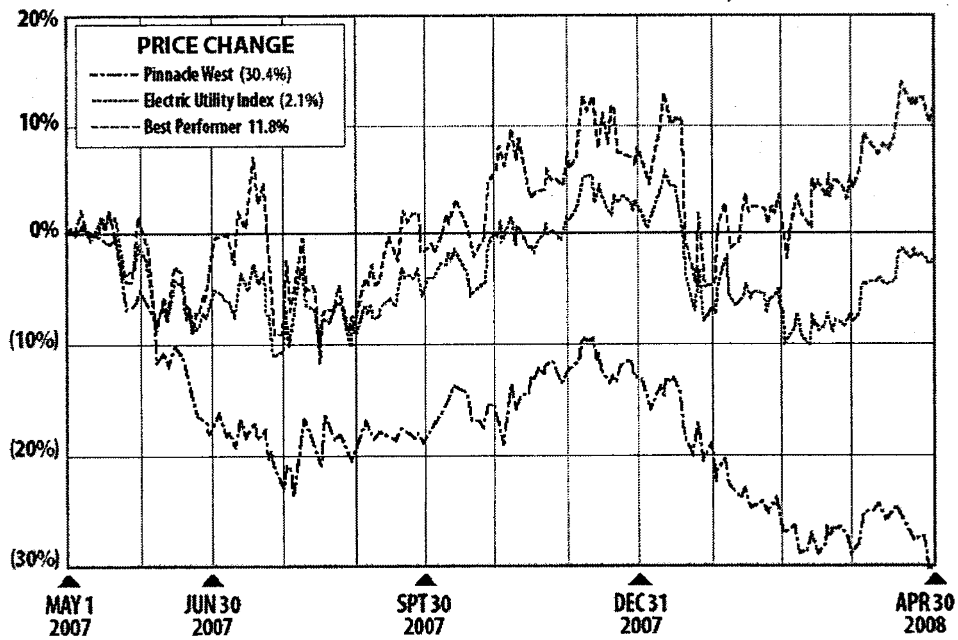


As this graph depicts, from 1993 to 2003, APS was able to limit its cash expenditures to the amount of cash the Company took in, resulting in positive net cash flow and a financially strong utility. One might consider this a "budget surplus" condition, from a state and local government point of view. In 2003, however, that trend reversed, and the Company's required cash outlays began to exceed its cash receipts by significant amounts – a negative cash flow that has resulted in weakening credit metrics and declining financial health. In other words, the Company is now in a "budget deficit" position. Indeed, even with the benefit of the rate increase authorized in Decision No. 69663, APS still experienced a 2007 "budget deficit" of $422 million.

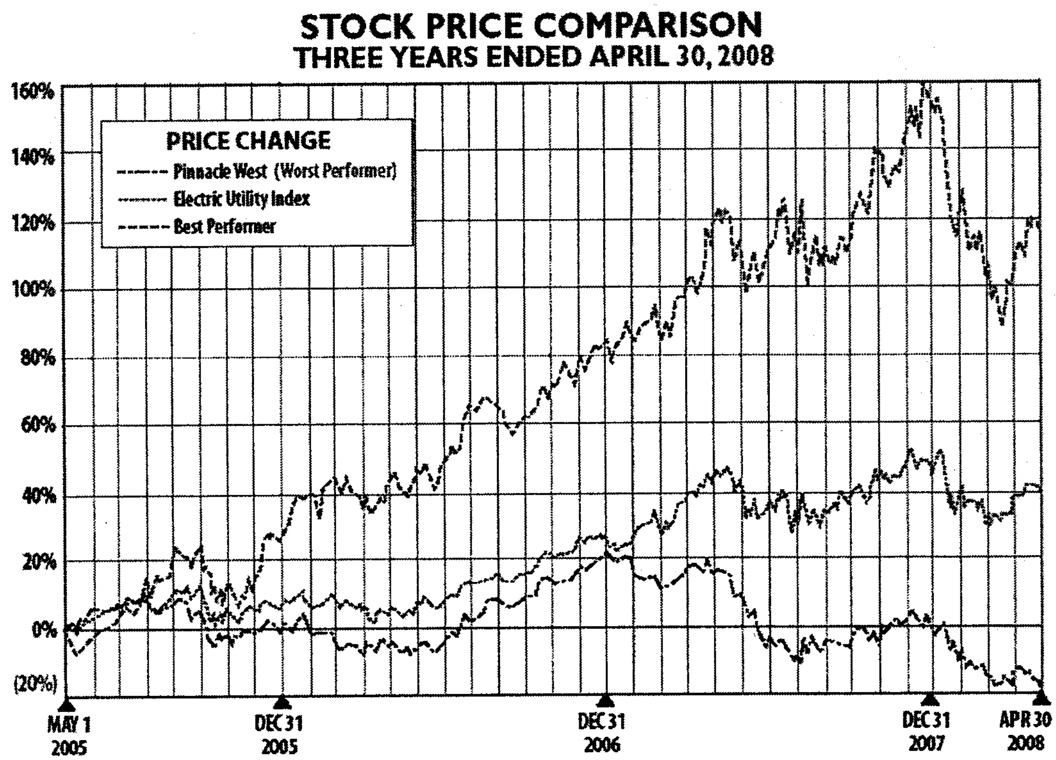
19. APS's subpar financial performance has caused Pinnacle West's stock value to fall considerably, particularly when compared to others in the industry (an industry composed of other investor-owned utilities with which the Company competes for equity

capital investment). As the following shows, of the investor-owned utilities ranked in the S&P electric utility index over the twelve months ended April 30, 2008, Pinnacle West ranked **dead last**, with a loss of stock value of **30.4%**.

STOCK PRICE COMPARISON
TWELVE MONTHS ENDED APRIL 30, 2008



20. A longer-term historical look at APS's stock performance does not improve the investment perspective. As the following depicts, Pinnacle West again has the worst performing stock among members of the S&P electric utility index when examining the three years ended April 30, 2008. While the industry averaged a 40.8% increase in value during this period, Pinnacle West's stock value dropped by 19.5% – again placing Pinnacle West dead last.

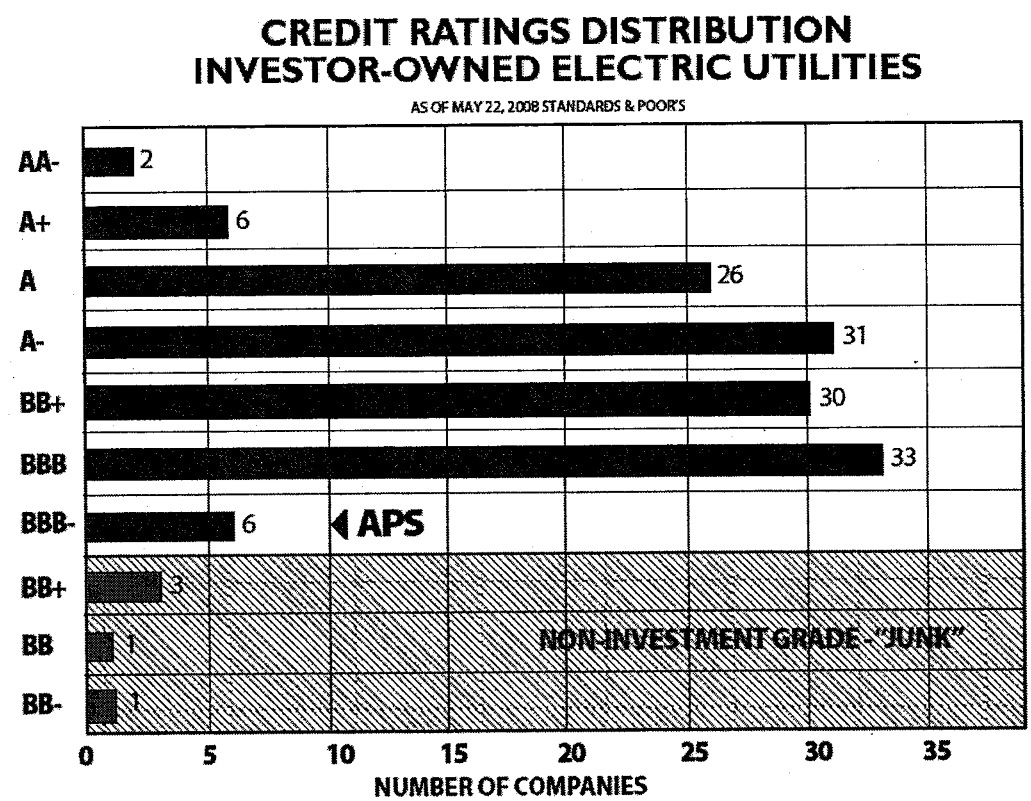


21. This sagging stock performance is easily attributable to APS's chronic inability to earn its authorized ROE and the resulting massive underearnings, as well as apparent pessimism concerning the likelihood of any considerable improvement in the foreseeable future. Investors have little incentive to invest in Pinnacle West with such poor financial returns, especially when their prospect for financial gain is so much better if they invest in the many other better performing utilities nationwide.

22. If the Company is unable to attract sufficient equity investment, APS must either finance its capital expenditure requirements through the debt markets or restrict capital spending by foregoing necessary projects at the risk of jeopardizing service reliability. The second option is hardly a reasonable one from any perspective, and the first – accessing the debt markets and the attendant costs to customers – depends entirely on the Company's credit ratings.

23. The cost that APS must pay for the debt it issues to fund capital expenditures is based on its credit ratings. Every decrease in APS's credit rating increases the cost to the Company – and its customers – of that debt. As described in the Company's general rate application, those costs increase dramatically when a company's credit rating falls to a junk level. For that reason, both APS and its customers have a strong interest in maintaining APS's investment grade credit ratings.

24. APS's credit ratings on its outstanding debt are currently among the lowest that they can possibly be without being regarded as "junk," rated "BBB-" by Standard & Poor's ("S&P"), "BBB" by Fitch Ratings ("Fitch"), and "Baa2" by Moody's Investor's Service ("Moody's). Significantly, APS's credit ratings are among the very worst of the industry. As the following shows, only **five** of the 139 rated investor-owned electric utilities are rated lower than APS.



25. APS thus dangles precariously on the precipice of junk status, and does not have far to fall. And with APS's growing earnings attrition, its financial credit metrics are sliding into junk range. As described in the underlying rate application, credit rating agencies base their credit ratings of companies on certain financial criteria that measure a company's financial health, performance and risk. The rating agencies have established financial metrics as guidelines for determining a credit rating. The key financial metric examined by the credit rating agencies is the FFO/Debt ratio, which measures the sufficiency of a company's cash flow to service both debt interest and debt principal over time.

26. To maintain a BBB credit rating in the Company's present "business profile" category, S&P expects APS to maintain a FFO/Debt ratio of 18% to 28%. But even if Pinnacle West decides and is able to infuse $400 million of equity into APS in 2008 (and Pinnacle West has taken the appropriate first steps with the Commission to do so, as I will discuss below), the Company fully expects that its FFO/Debt ratio will sink below the 18% threshold to junk just next year, falling to 17.6% at the end of 2009 and to 16.6% at the end of 2010 under present rates. These metrics mean that APS faces the real threat of downgrade during the pendency of its general rate case if the Commission does not take action to minimize the negative impact of regulatory lag and provide a much-needed safety cushion against a ratings downgrade in the interim.

27. This fact has not gone overlooked by the rating agencies. As recently as January 31, 2008, S&P expressly commented on APS's weak credit metrics and indicated that the Company's "[r]atings could be lowered to speculative [non-investment] grade if the company is not able to overcome the challenge of ensuring timely recovery of its prudently incurred costs through rate increases approved by the ACC." Standard & Poor's Ratings Direct, "Summary: Arizona Public Service Company," January 31, 2008. Moody's has also expressed this sentiment, explaining that "[g]iven APS's current

significant capital expenditure program, the company will require continued, timely regulatory support to maintain credit metrics that are appropriate for its ratings." Moody's Credit Opinion: Arizona Public Service Company, December 17, 2007. Fitch, too, has noted that the Company's "earnings and cash flow attrition due to regulatory lag and/or unanticipated disallowances is a significant challenge to the sustainability of PNW and APS's investment grade credit ratings. Revenue increases below our expectations or undue delay would likely result in credit rating downgrades." Fitch Press Release, "Fitch Revises Pinnacle West's Outlook to Negative, Affirms 'BBB-' IDR, December 21, 2007.

28. The consequences of a downgrade to junk are dramatic and enduring. APS's current feeble credit ratings – and the very real prospect that those ratings will worsen still – have already caused APS's borrowing costs to increase compared to what they were just a few years ago (before the Company was downgraded by S&P to BBB- in 2005). These increased costs, which result from higher interest rates, will further rise by as much as $70 million to $145 million per year by 2019 if the Company falls just that one step further into non-investment grade – approximately **$1 billion** of additional costs over the next ten years that would ultimately be borne by APS customers.

29. More significantly, and in addition to the other perils that accompany junk credit status described in my testimony supporting the Company's general rate filing, a downgrade might easily cause APS to entirely lose access to the credit markets – particularly in today's volatile credit environment. Indeed, the Company's ability to access the debt markets has already been limited on two separate occasions in 2007 when the credit market was under severe stress. Without access to credit markets and lacking the ability to attract equity investment, APS would have no alternative but to either charge rates sufficient to allow APS to internally finance the Company's billion dollar per year spending obligations or to forego necessary capital projects entirely at a very high risk to service reliability.

Company's Actions to Improve Financial Condition

30. As described in detail in the Company's general rate application, APS has taken a series of actions to improve its financial condition and forestall a downgrade to junk pending permanent rate relief from the Commission. Among other things, APS has initiated the process of eliminating 300 employee or supplemental employee positions – thus further improving its already impressive 224 to 1 ratio of customers per APS employee (a rise in productivity compared to the Company's 198 to 1 customer-to-employee ratio just ten years ago). The Company also underwent a reorganization in late 2007 to enhance the speed and efficacy of decision-making and become more customer-focused, thus additionally improving APS's operational efficiencies. Budget requests for 2008, both capital and operating, were revised downward to help cope with the rising costs of the Company's key materials and components. APS also continues to manage its debt aggressively, saving the Company millions of dollars in financing costs.

31. In yet another internal effort to prevent a downgrade to junk, APS's parent, Pinnacle West, invested $460 million of additional equity into APS during 2005 and 2006 (a sacrifice to shareholders whose investment was thus diluted in the face of already subpar returns), thereby improving the Company's key FFO/Debt ratio to the extent possible during that tense financial time. Pinnacle West currently has another request pending before the Commission for a potential additional $400 million equity infusion into APS later this year. *See* Docket No. E-01345A-08-0228. But even if that request is granted, and even if Pinnacle West is able to issue the massive amounts of equity required to keep APS within investment grade for the balance of 2008, APS's FFO/Debt ratio would subsist within investment range for only a short time – until mid-to-late 2009 – after which time it falls again into junk grade.

32. Thus, by the time in late 2009 or 2010 that the Commission will have rendered any decision on the Company's permanent rate application, the Company's

FFO/Debt will have dropped once again into junk range. Pinnacle West will unlikely be able to infuse equity into APS again prior to that time in order to avert the further deterioration of the Company's credit metrics.

33. Should the Company's ability to charge new rates be delayed at all beyond the requested effective date of October 1, 2009, APS will be left teetering on the verge of junk with no safety margin to guard against the impact of even the slightest unanticipated financial hit. Last minute interventions by the Commission when confronted with such a circumstance may not be enough to prevent a downgrade from the rating agencies even before a decision is rendered on APS's permanent rate application without tangible evidence in the interim that the Company is supported by its regulators and that its financial condition is likely to improve.

Impact of Granting the Requested Interim Relief

34. Granting the Company's request for interim relief would allow continued development of the customer-centered programs described earlier and would clearly provide ratings agencies with critically necessary evidence of on-going regulatory support (evidence that may be enough to prevent a downgrade even in the face of weak credit metrics), and would further provide a modest level of safety margin for the Company until the Commission acts on the pending application for permanent rate relief. Moreover, under the Company's proposal, this important benefit for APS can be realized with no increase to customer bills compared to what customers are already paying today and would offset 41% of the rate increase requested in the Company's permanent rate application.

35. The Company's interim rate proposal works as follows: Decision No. 69663 permitted the Company's 2007 Annual PSA Adjustor of $.003987 per kWh to continue past January 31, 2008, until APS had recovered an additional $46 million of fuel and purchased power costs. APS anticipates that it will have collected this sum and that

the PSA surcharge will thus expire in July or August of 2008. In this Motion, APS proposes that – in order to mitigate the impact of regulatory lag and prevent APS's credit metrics from slipping into junk range before the Commission has the opportunity to rule on its general rate application – the Commission approve an interim base rate surcharge of $.003987 per kWh (roughly "four mils"), to become effective upon the expiration of the $.003987 per kWh 2007 Interim PSA Adjustor. Part of the revenue received from this request will be used to help cover the costs of the approximately $1.7 billion worth of ACC-jurisdictional facilities that have already been built since the end of the Company's last test year and that are already serving APS customers, but which are not recovered under current rates. The Company also proposes that this rate be subject to refund, with interest, at the close of the Company's permanent rate application. Thus, APS customers are protected in the event that the final rate order is for less than this approximately four mil increase in base rates. In that event, not only would permanent rates then be reduced, but customers would receive a full refund, plus interest, of any over-collection.

36. If the Commission approves the Company's interim request, the Company's ACC-jurisdictional ROE rises to 9.4% in 2008 and to 8.3% for 2009. Although these numbers are still significantly less than the 10.75% ROE approved in Decision No. 69663, they are meaningful improvements to the status quo. By granting the requested interim relief, the Commission would reduce the Company's anticipated cumulative earnings shortfall by $100 million between now and year-end 2009.

37. Moreover, the additional revenue generated from the interim rate proposal would suffice to keep APS's FFO/Debt ratio above the 18% threshold and within investment range through the end of 2009, thus mitigating the impact of regulatory lag and giving the Company a moderate cushion of support pending a decision on the permanent rate application. Under APS's interim proposal, FFO/Debt rises by 2% in 2009 to 19.6% as of December 31, 2009. Granting the Company's interim rate request

will thus likely allow APS to circumvent the threat of downgrade to junk during the course of those rate proceedings, assuming the rate case can be resolved and APS is able to charge the resultant permanent rates by early 2010. Granting such interim relief is thus consistent with the Commission's historical recognition that "the benefits of higher bond ratings inure to both the utility and the ratepayer" and therefore that "sound and responsible regulatory action by this Commission is fundamental to the maintenance of desirable bond ratings." Decision No. 51009 (May 29, 1980).

38. The Company's interim rate proposal also works to the benefit of APS's customers. Because APS proposes that the amount of the interim base surcharge should be identical to that of the Interim PSA Adjustor, by timing a large part of the Company's needed non-fuel electric rate increase to coincide on an interim basis with the roll-off of the PSA charge, customers will see no change in their bills if the Commission grants this request above what they are already paying today. Moreover, the interim increase in base revenues, if eventually made permanent in the underlying general rate proceedings, will reduce the incremental impact of the permanent rate request on APS customers by at least 41%. It would, in essence, operate as a phase-in of new rates.

39. In other words, the interim rate proposal provides the Commission with the important opportunity to protect customers from feeling the financial impact of misleading "yo-yo" rates – rates that are temporarily adjusted downward (and further below cost) in July or August only to be kicked back up again by a larger amount at the conclusion of the Company's general rate proceedings. The bill will not go down at the end of this summer, but it will not increase as substantially at the close of the Company's general rate application as it would absent approval of this interim request. Preventing customers from experiencing such rate volatility was specifically cited by the Commission as a reason for allowing Tucson Electric Power to retain a component of its rates that, like

the Company's Interim PSA Adjustor, was scheduled to expire during the course of that utility's general rate proceedings. *See* Decision No. 69568 (May 21, 2007).

40. In addition, the Company's interim proposal has the further benefit of sending appropriate price signals to customers during the time of year when demand on the APS system is at its peak and system costs are at their highest – a result that is not achieved if customers are given a temporary price *decrease* at the exact time of year when customers need to conserve energy the most, only to see those rates significantly increase again later.

41. Perhaps most importantly, customers substantially benefit from the moderate financial improvement to APS's financial health that will result during the general rate proceedings if the Commission grants this application and provides the Company with a cushion of protection against a downgrade to junk status. The proposed \$.003987 interim surcharge will result in a one time "phase-in" of \$115 million (pre tax) annually against the Company's permanent revenue request (which amount would be refundable with interest at the close of the rate case if the interim relief is greater than the permanent rates allowed). The trade-off of denying that request is the significantly high risk that customers will have to fund over the long-term revenue requirements of hundreds of millions of dollars more if the Company is not able to stave off a downgrade to non-investment credit ratings.

Conclusion

42. APS's current rates do not compensate it for its cost of service. The Company is not able to collect anywhere near the amount of legitimate and prudently incurred costs it has spent and must continue to spend during the course of the permanent rate proceedings to ensure reliable electric service. As a result, notwithstanding proactive efforts from the Company and Pinnacle West, APS's credit metrics will fall into junk credit range during the course of the Company's rate proceedings, before the Commission

is likely to grant the much-needed rate relief. I firmly believe that the Company will more than likely be downgraded to junk during the pendency of the general rate case proceedings without interim relief.

43. The need for interim rates is compelling – the issue is whether and when the Commission grants them. In this regard, the Company's Motion for Approval of Interim Rate and Preliminary Order provides the Commission with the following several opportunities – opportunities that could well be lost if the Commission does not take emergency action: (1) to protect the Company from downgrade during the course of its general rate proceedings by granting an interim rate increase that will not result in an incremental increase to APS customer bills; (2) to fund continued development of projects that will promote efficiency, reliability, sustainability, safety, and customer choice; (3) to shield customers from experiencing a significantly higher rate increase at the close of these proceedings compared to what they would experience absent the interim relief; (4) to send appropriate price signals to customers during peak usage periods; and (5) to protect customers from the impact of rate volatility. Virtually all of these opportunities will be lost if the Commission does not act on the Company's Motion before the termination of the Interim PSA Adjustor in July or August of this year.

This concludes my affidavit.

State of Arizona)
) ss.
County of Maricopa)

I, Donald E. Brandt, having been first duly sworn, state that I have read the foregoing affidavit and that the same is true and correct to the best of my knowledge, information, and belief.

Donald E. Brandt

Subscribed and sworn before me this 6th day of June, 2008.

Linda G Redman
Notary Public

My Commission Expires:

Linda G. Redman
NOTARY PUBLIC – ARIZONA
MARICOPA COUNTY
My Commission Expires
February 8, 2011

EXHIBIT
APS-2
ADMITTED

REBUTTAL TESTIMONY OF DONALD E. BRANDT

On Behalf of Arizona Public Service Company

Docket No. E-01345A-08-0172

(Interim Rate Request)

September 8, 2008

Table of Contents

REBUTTAL TESTIMONY OF DONALD E. BRANDT ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY (Docket No. E-01345A-08-0172) (Interim Rate Request)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Donald E. Brandt. I am President and Chief Executive Officer of Arizona Public Service Company ("APS" or "Company") and President and Chief Operating Officer of Pinnacle West Capital Corporation ("Pinnacle West"). I am responsible for all aspects of APS operations, including generation, transmission, distribution, customer service, and general administrative functions. My business address is 400 North 5th Street, Phoenix, Arizona, 85004.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING THAT DESCRIBES YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. Yes. In addition to the Affidavit that I submitted in this interim proceeding (which serves as my Direct Testimony in this matter), I have also submitted Direct Testimony in the general rate case, which describes my educational and professional background.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to the Direct Testimony submitted by other parties in this proceeding. I will address three general areas: (1) why interim relief is appropriate for APS under the extraordinary challenges it is facing today; (2) the amount of interim relief that is warranted; and (3) why it is contrary to the public interest to condition the approval of interim relief or the timing of such an award on an issuance of equity by Pinnacle West.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I will begin by making some general observations about the testimony submitted by the various parties to this proceeding. Although there clearly are several areas of disagreement between APS and the other parties, there are also many important concepts and facts on which we agree or about which there appears to be no dispute:

- Interim relief can be appropriate even under certain "non-emergency" conditions, including when "the Commission is unable to process a utility's rate increase request in a timely manner" or "if other special circumstances are present." *See* Direct Testimony of Ralph C. Smith ("Smith Testimony") at 8.

- Credit ratings matter and are a relevant consideration in this proceeding. *See* Smith Testimony at 24-25, 32; Direct Testimony of David C. Parcell ("Parcell Testimony"), throughout.

- A downgrade of APS to non-investment or "junk" credit status would be undesirable and would increase costs to both the Company and customers, and it is therefore desirable to protect APS from a ratings downgrade. *See* Smith Testimony at 25.

- APS's rates are set using a historical test year coupled with rate cases that take between 18 to 24 months to complete. *See* Smith Testimony at 23.

- APS has faced and continues to face extraordinary capital expenditure requirements necessary to maintain its existing system, meet increasing demand, and perform environmental upgrades on generation plants. These capital expenditure needs are exacerbated by commodity cost inflation and foreign exchange pressure, factors entirely outside of the Company's control. *See* Affidavit of Donald E. Brandt ("Brandt Affidavit") at 5-6 (undisputed).

- Under even a basic "non-controversial" analysis of net rate base additions since the last APS rate case, APS's ACC-jurisdictional rate base has increase by over a half a billion dollars ($1.114 billion of new investment as of December 31, 2007, net of accumulated depreciation), which is not reflected in the rates – an amount that does not include any of the significant plant additions placed in service since December 31, 2007 or the impact of book depreciation on any new plant additions. *See* Smith Testimony at 33.

- APS is currently realizing Returns on Common Equity ("ROE") well below its authorized 10.75% rate of return. Under present rates, the Company's actual ACC-jurisdictional ROE was only 9% in 2007, and falls to 8.4% in 2008 and 6.3% in 2009 absent rate relief, resulting in a tremendous earnings shortfall. As a result, APS faces the loss of $384 million in authorized ACC-jurisdictional earnings (assuming a 10.75% ROE) from the end of the December 31, 2007 Test Year through 2010 (which is additive to and more than doubles the $321 million earnings shortfall that APS has experienced over the past five years). *See* Brandt Affidavit at 7 (undisputed).

- The Company's subpar financial performance has caused Pinnacle West's stock price to fall below book value, with stock performance that ranks dead last compared to that of its industry peers. *See* Brandt Affidavit at 9-10 (undisputed).

These acknowledged or apparently undisputed facts show that, contrary to Staff's consultants' and RUCO's respective conclusions, the impact of regulatory lag on APS is anything but "ordinary." In the current operating environment, beset by severe inflation in core commodity costs, increasing global demand, the falling value of the dollar in the foreign exchange market, vigorous competition for utility capital, and challenging credit and capital markets in the face of unprecedented future capital expenditure requirements, the excessive regulatory lag is debilitating to the Company's financial health and its ability to maintain investment grade credit metrics during the course of the Company's general rate proceeding. Further, none of these external factors can be substantially offset by "cost management." These are the very type of "special circumstances" that justify the granting of interim relief.

Staff's consultants do not dispute that public policy requires APS to be kept financially sound or the fact that APS suffers from an earned ROE far below its authorized ROE and a declining FFO/Debt ratio. Rather, they understate the significance of those factors to APS and its customers by simply questioning APS's assertion that, as a result, the Company will likely face a ratings downgrade before any new rates from the general rate case will take effect. As I will show, their analyses of how the credit rating agencies perceive APS reflect neither how credit rating agencies operate nor the pivotal significance of APS's declining credit metrics – particularly the highly important FFO/Debt ratio.

Under the extraordinary circumstances presented in this case, simply hoping that permanent rate relief will come through in time to prevent a downgrade to junk is both dangerously reckless and contrary to the public interest. It is not prudent public policy to permit Arizona's largest electric utility to be kept teetering on the brink of junk status, particularly given the significant challenges and opportunities facing the State's energy future. The goal cannot be to keep APS at an 18% FFO/Debt level and earning far below its authorized ROE, with no buffer against external factors and limited ability to invest both in basic infrastructure and in the resources, programs and technologies that will contribute to an efficient, sustainable, and reliable energy future for the Company's customers. Rather, these circumstances require proactive, innovative measures, including interim rate relief, to mitigate the extraordinary impact of regulatory lag, protect APS from downgrade, and give APS the financial wherewithal to provide its customers and the State with the important benefits that the Company – and, I believe, the Commission – have deemed to be necessary and in the public interest.

III. THE COMPANY IS CURRENTLY FACING EXTRAORDINARY CONDITIONS THAT JUSTIFY THE AWARD OF INTERIM RELIEF.

A. Interim relief is not dependent upon the showing of an emergency.

Q. DO YOU AGREE WITH RUCO'S ASSERTION THAT INTERIM RELIEF MAY BE GRANTED ONLY UPON THE FINDING OF AN EMERGENCY?

A. Although this is a legal issue that I expect the parties will brief, it is my understanding, from both the Company's legal analysis (reflected in the Company's Motion for Interim Relief) and my own observation from other cases, that an emergency is not required. Even as Staff Witness Smith articulates it, no finding of "emergency" must be made for interim relief to be appropriate. As Mr. Smith notes, in his experience, interim rates may be granted under any of three circumstances, two of which do not require an "emergency": "if the Commission is unable to process a utility's base rate increase in a timely manner, if the utility is experiencing an emergency, or if other special circumstances are present." *See* Smith Testimony at 8.

I cannot imagine that the framers of the Arizona Constitution gave the Commission broad authority over utility rates, yet would proscribe that authority to limit the Commission's ability to proactively address the extraordinary circumstances that confront APS today. I agree with an analogy that Commissioner Pierce drew during the Procedural Conference in this matter: that it is important to clear the trees from the forest before the fire arrives, rather than trying to protect the area's residents from harm in the heat of the flames.

B. Under Staff's articulated standards, APS has shown that interim relief is appropriate under the Company's current circumstances.

Q. HOW DO YOU RESPOND TO MR. SMITH'S AND RUCO'S SUGGESTION THAT APS'S REQUEST FOR INTERIM RELIEF SHOULD BE DENIED BECAUSE "ORDINARY" OR "NORMAL" REGULATORY LAG "BY ITSELF" DOES NOT JUSTIFY INTERIM RELIEF?

A. Such statements are irrelevant here since APS is experiencing anything but "ordinary" or "normal" regulatory lag. To the contrary, APS is experiencing **extraordinary** regulatory lag in the face of **extraordinary** operating conditions, causing the Company significant (and undisputed) financial harm, and threatening the Company's ability to protect itself from a ratings downgrade during the course of the general rate proceedings. These conditions are the very "special circumstances" that warrant interim relief under Staff's own articulated standards. *See* Smith Testimony at 8, 32.

Q. PLEASE EXPLAIN WHAT YOU MEAN WHEN YOU SAY THAT APS IS EXPERIENCING "EXTRAORDINARY" REGULATORY LAG?

A. It is undisputed in this case – and well known (and often mentioned) by credit rating agencies and analysts – that rate cases for APS have historically taken 18 to 24 months to complete. This extensive period of regulatory lag is longer than that of virtually every other jurisdiction in the country and, given the lack of any compensating mechanisms, the most damaging. As one utility research and analysis firm recently commented, "**the extent and consistency of the exorbitant regulatory lag in Arizona is without comparison in the industry**." *See* Regulatory Research Associates, Utility Focus on Pinnacle West Capital, March 14, 2008, attached hereto at Attachment DEB_RB-1. As I noted in my Affidavit, credit rating agencies also routinely comment on Arizona's extensive regulatory lag as one of the challenges that APS must overcome if it is to remain investment grade.

Compounding the cost recovery issues inherent in such regulatory lag, the Commission also uses a historical test year, which Staff has recently suggested means a test year that requires significant experience under present rates. This means that the current regulatory framework could, for example, prevent APS from even beginning to recover prudently incurred costs for up to **three years** after that investment was made and the plant was placed in service. Such extraordinary delay under the Company's current operating conditions institutionalizes economic confiscation of invested capital and causes APS significant financial harm that threatens its already precarious credit metrics.

Moreover, contrary to Mr. Smith's suggestion, such a regulatory regime does not simply require the Company "to bear the cost of new plant additions temporarily." *See* Smith Testimony at 13. Because depreciation expense, property taxes and capital carrying costs begin for new investments the moment that they are placed in service, regulatory lag deprives the Company of the ability to **ever** recover some of those costs. The resulting **permanent** loss of revenue is both substantial and debilitating when the required investments are as great and the lag time is as long as both are now for APS.

Q. PLEASE DESCRIBE THE "EXTRAORDINARY CONDITIONS" TO WHICH YOU EARLIER REFERRED.

A. As I described in my Affidavit and in greater detail in my Direct Testimony for the general rate case, APS has faced and continues to face extraordinary capital spending requirements that are necessary for APS to maintain the reliability of its existing system, meet increasing demand, perform environmental upgrades on its aging generation plants, and invest in the technologies that APS (and, I believe, the Commission) has determined to be important for customers and consistent with the public interest. These cost pressures are exacerbated by a number of external financial pressures that are entirely outside of the Company's control, including corrosive inflation of the Company's core commodities costs, the falling value of the dollar in the foreign exchange market, increasing competition for utility capital, and difficult and volatile credit and capital markets.

Importantly, the fact that APS is challenged by these rising costs was not disputed by Staff or any other party to this proceeding. Nor can it be. As described in an analysis recently conducted by the Federal Energy Regulatory

Commission ("FERC") into the causes of and responses to rising electricity costs, APS's cost pressures are shared by utilities across the nation, and are reflected in rising costs of electricity nationwide. The FERC report notes that electricity prices are rising because of unprecedented cost increases, including significant capital expenditure costs related to the need for sizeable new investment in generation, distribution, and transmission construction that are inflated by, among other things, rising global demand for basic materials, increasing labor costs, and uncertainty about the financial impact of future climate change legislation. This rising cost trend is also observable elsewhere in Arizona. Salt River Project ("SRP") – Arizona's second largest utility, next to APS – has increased rates by 26.7% since 2002 and has recently requested that its Board of Directors approve a second rate increase of another 5% to 7%, which, if approved as requested by November 1 of this year (so that the increase would phase-in with SRP's lower winter electric prices, exactly as APS has requested here), would raise SRP's rates by a total of over **30%** in just the past six years. *See* page D1 of the Arizona Republic, September 6, 2008.

Characterizing the cost pressures facing the electric utility industry, FERC Chairman Joseph Kelliher concluded, "[w]e must accept that the U.S. cannot make the massive investments necessary to assure security of our electricity supply, make additional large investments to confront climate change, and lower electricity prices at the same time. If we try to do all three, the result will likely be failure." *See* Attachment DEB_RB-2. Similar studies reaching almost identical conclusions were attached to my general rate case testimony at Attachment DEB-2.

Q. WHAT IMPACT HAVE THESE EXTRAORDINARY COST CONDITIONS HAD ON THE COMPANY'S FINANCIAL HEALTH?

A. The Company's capital investment requirements, coupled with extensive regulatory lag, have caused its cash outflows to far exceed cash inflows – deficit spending that results in a significant deterioration of the Company's financial health and requires APS constantly to battle to maintain investment grade credit metrics that lie just on the brink of "junk" credit status. This is hardly a desirable condition for Arizona's largest utility, with the duty to provide reliable service to over one million Arizonans.

Significantly, no party to this proceeding disputes the negative impact that the current operating environment has on APS's financial condition to any real degree. Staff's consultant, Mr. Smith, asserts – without any substantiating evidence or analysis – that there "may not" be merit to the Company's contention that its incremental revenues are insufficient to keep up with its growing costs. But that suggestion is undercut both by (1) the independent assessment by S&P cited on page 18 of Mr. Smith's testimony, noting that APS's significant capital spending needs are "expected to drive negative free operating cash flows for the foreseeable future"; and (2) Mr. Smith's ultimate conclusion that, under the most basic "non-controversial" analysis, the Company has invested $538 million in net ACC-jurisdictional plant necessary to serve customers that is not reflected in rates. The latter point makes it self-evident that APS's revenues have not been sufficient to meet its growth in rate base. *See* Smith Testimony at 12-14.

Neither does any party contest that credit rating agencies are well-aware of the debilitating impact of APS's unusually protracted regulatory lag on the

Company's financial condition under these circumstances. This critical point is underscored in the June 2008 S&P report quoted at length on page 18 of Mr. Smith's testimony, which notes that "[t]he use of a historical test year in Arizona, coupled with the fact that fully litigated rate cases take between 18 to 24 months to complete, is expected to result in no meaningful improvement in financial performance through 2009 and possibly beyond, depending upon the timing and the outcome of the company's current case." However, Mr. Smith omitted to include in his lengthy quotation the ultimate conclusion that S&P reached in that report: that, notwithstanding the currently "stable" outlook, "[r]atings could be lowered to speculative grade if the company is not able to overcome the challenge of ensuring timely recovery of its prudently incurred costs through rate increases approved by the ACC." *See* Attachment RCS-2 to Mr. Smith's Testimony at 22.

As APS has repeatedly made clear in this and other matters, the Company's inability to timely recover its investment has deprived it of the opportunity to actually earn its allowed rate of return for the past several years – a fact undisputed by any party to this proceeding. Going forward, APS projects to earn a mere 8.4% ACC-jurisdictional ROE in 2008 (compared to its allowed return of 10.75%), a number that falls to 6.3% in 2009 without intervening rate relief – again, facts that are not disputed by any party to this proceeding. As a result, APS faces the loss of $384 million in authorized ACC-jurisdictional earnings (assuming a 10.75% ROE) from the end of the December 31, 2007 Test Year through 2010 (which is additive to and more than doubles the $321 million earnings shortfall that APS has experienced over the past five years).

The Company's earnings attrition is entirely related to the fact that its present rates do not compensate the Company for its non-fuel cost-increases. Such subpar financial performance has placed in serious risk the Company's ability to attract at a reasonable cost the capital necessary to finance its capital program and damaged its credit metrics, causing them to hover at dangerous levels during the course of the Company's general rate proceedings absent proactive, pre-emptive Commission action.

Q. YOU MENTIONED THAT UTILITIES ACROSS THE NATION FACE THE SAME COST PRESSURES AS APS. ARE THESE UTILITIES EXPERIENCING THE SAME FINANCIAL HARM THAT YOU HAVE DESCRIBED FOR APS?

A. Generally not. Although utilities across the nation are challenged by many of the same cost pressures now facing APS, most perform far better financially compared to APS and have secured much higher credit ratings. As explained in my Affidavit, APS's credit ratings on its outstanding debt are among the very worst of the industry, with only five of the 139 investor-owned electric utilities rated by S&P rated lower than APS. *See* Brandt Affidavit at 11. And while Staff consultant David Parcell attempts to show that the Company's bond ratings are only **"somewhat less"** than those of other electric utilities, his position is at odds with the very evidence he cites – a table generated from an August 2008 AUS Utility Report (correcting the table printed on page 10 of Mr. Parcell's Testimony, in response to a discovery request from APS), which demonstrates that, of the 47 companies included in the report rated by Moody's, only **4** are rated worse than APS (with **23** such companies rated higher), and that S&P rated only **1** of the 50 utilities included in the report below APS (with **40** such companies rated higher). *See* Staff Response to APS 3.1, attached hereto at Attachment DEB_RB-3.

APS's comparatively worse credit ratings are unquestionably linked to its inability to overcome the financial challenges posed by the Company's capital requirements in its current regulatory environment and the undeniable fact that our prices are below costs. Unlike other jurisdictions with utilities facing similar cost-challenges, Arizona has no mechanism in place to mitigate the deleterious impact of regulatory lag on APS's ability to recover its substantial non-fuel costs. Such mechanisms include, for example, the use of a future test year in setting rates so that future revenues are better aligned with future costs, thus mitigating the earnings attrition impact of regulatory lag. States using such a mechanism include Alabama, Arkansas, California, Delaware, Florida, Georgia, Hawaii, Idaho, Illinois, Maryland, Minnesota, Mississippi, North Dakota, New Jersey, New York, Pennsylvania, and Wisconsin.

For those states, like Arizona, that use a historical test year in setting rates, many require that rate cases be resolved within a short time frame – often six to ten months or less – in order to avoid the negative financial impact of protracted regulatory lag. In Arkansas, for example, rate cases must be resolved within 10 months, or utilities are permitted to automatically place proposed rates in effect under bond and subject to refund pending the completion of the rate case proceedings. In Connecticut, rate cases must be completed in six months, or the proposed rates may become effective until the rate case is resolved, subject to refund. Delaware requires that rate cases be finalized in seven months, permits interim rates after 60 days, and utilities may automatically place any requested increase not above 15% into effect subject to refund if the seven months timeframe is not met. In Mississippi, if a rate case is not complete within four months, the full request may be implemented under bond subject to refund. Numerous other states provide for interim rates to be implemented if a case is not decided within a specified timeframe, often six to 10 months, including Connecticut, Georgia, Kansas, Kentucky, Mississippi, New Hampshire, Oklahoma, and Utah. The more general use of interim rates to mitigate the impact of regulatory lag is permitted in Arkansas, Delaware, Florida, Hawaii, Iowa, Maine, Montana, New Jersey, North Dakota, Oregon, Rhode Island, Texas, and Virginia.

APS is also aware of several jurisdictions, in addition to Arizona, that have allowed explicit "attrition" adjustments, index adjustments, or other mechanisms to protect against the negative impacts of regulatory lag. For instance, Alabama has implemented a mechanism pursuant to which a utility's rates are reviewed annually under a forecasted test year, and are adjusted to ensure that Alabama's utilities are earning an allowed 13.0% to 14.5% ROE. Under a corollary "Earnings Sharing Mechanism," if the utility earns in excess of 14.5%, customers are fully refunded the overage at the time of the annual adjustment. No "traditional" rate cases have been filed in Alabama since this plan was implemented. Similar "earnings sharing," "attrition" or indexed adjustment mechanisms are used in jurisdictions including California, Georgia, Iowa, Louisiana, Maine, Massachusetts, Mississippi, North Dakota, Oklahoma, and Vermont.

As the foregoing shows, regulatory jurisdictions throughout the country are taking proactive, innovative steps to reduce the negative earnings impact of regulatory lag on their respective states' utilities. Disregarding those significant impacts out of strict adherence to "tradition" is neither reasonable nor constructive, and will ultimately harm APS, its customers and the State of Arizona over the long-term.

Q. THE COMMISSION HAS RECENTLY APPROVED SEVERAL ADJUSTMENT MECHANISMS FOR APS. DO THOSE MECHANISMS HELP RELIEVE THE COMPANY'S FINANCIAL CONDITION?

A. APS currently has in place several Commission-approved adjustment mechanisms that have improved the Company's previous cash flow problems, including particularly the Power Supply Adjustor ("PSA") and the Transmission Cost Adjustor ("TCA"). APS acknowledges these constructive measures, some of which have unquestionably forestalled a downgrade to junk to date. There is little question that, by resolving the Company's significant fuel cost recovery problems, the PSA in particular saved the Company from a downgrade following the conclusion of the last rate case, and, in all likelihood, protected APS from financial insolvency.

Nevertheless, it is important to recognize that, except for the TCA, these mechanisms are simply operating cost pass-through provisions, which do **not** provide earnings to the Company. The PSA, for example, does not prevent the Company's growing earnings attrition and thus cannot resolve the fundamental financial difficulties caused by APS's increasing non-fuel costs in an environment of extensive regulatory lag.

Q. HOW DO YOU RESPOND TO STAFF'S DISCUSSION OF THE "USEFUL FUNCTIONS OF REGULATORY LAG" ON PAGES 12 AND 13 OF MR. SMITH'S TESTIMONY?

A. I am responsible for running an electric utility that has a legal obligation to provide reliable service to both current and – just as important – future customers, irrespective of whether the cost of doing so outweighs the immediate financial benefit to APS of whatever incremental revenue those customers provide. Mr. Smith's suggestion that APS has the luxury of simply rejecting projects that do not survive some sort of "cost-benefit analysis" ignores the Company's duty to serve and anticipate the future needs and opportunities facing our State.

It is undeniable that APS has an obligation to provide reliable service to every present and future customer residing in its service territory, and, as the designated "provider of last resort," must remain ready and able to connect even those customers that do not receive service from APS today but that might someday request it. This means that APS is required not only to maintain a reliable distribution and transmission system that can serve present and future customers, but that it must also invest in (or otherwise acquire) the generation resources necessary to meet all of the growing energy demand within its service territory. As Arizona's largest utility, the Company is also keenly aware of its responsibility to comply with the Commission's policy directives to invest in resources and technologies that will promote a sustainable energy future for Arizona and allow Arizona's economy to continue to prosper (as APS Witness Bill Post discusses in his Rebuttal Testimony).

Significantly, neither Staff's consultants nor any other party to this proceeding disputes that most, if not all, of APS's capital costs are essential for APS to maintain reliable service, meet demand, and continue to implement the customer-beneficial programs and technologies that this Commission has found to be in the public interest. The massive costs facing APS thus cannot be avoided without sacrificing either service reliability or Commission-endorsed, customer-beneficial programs, and the Company simply cannot "cost manage" its way into financial health during the extensive period of regulatory lag by performing a "cost/benefit" analysis on its intended capital projects and rejecting as an inappropriate business risk any project that "is not cost-justified or [for which] the benefits are too speculative to warrant the commitment of funds," as Mr. Smith suggests. *See* Smith Testimony at 13.

If APS is required to continue to bear the entire "cost responsibility for plant additions and operating cost increases during the period between rate cases," notwithstanding the extraordinary length of such period and the fact that such lag results in a permanent forfeiture of earnings, loss of financial health, and deteriorating credit metrics (as Mr. Smith suggests regulatory policy requires), socially desirable and customer-beneficial projects will necessarily be sacrificed in favor of whatever investments APS can still afford to make to meet its obligation to provide basic, reliable service to its customers. The Company never wants to be placed, for example, in the position that PacifiCorp's subsidiary, Rocky Mountain Power, is now in: PacifiCorp recently announced that, because the Utah public utility commission did not grant Rocky Mountain Power a rate increase that was sufficient to cover its cost of providing electric service, it would be forced to terminate services aimed at ensuring the reliability of its system (such as the payment of overtime to employees to promptly respond to system outages, except where public safety is threatened). *See* PacifiCorp Press Release, September 2, 2008, attached hereto at Attachment DEB_RB-4.

If APS is downgraded during the course of its general rate proceedings, as I believe is more likely than not without interim relief, there is a virtual guarantee that even the currently planned Solana project will be abandoned in light of a contractual clause in the Company's contract with Abengoa that allows Abengoa to forego the project if, because of APS's financial condition, Abengoa cannot obtain the necessary financing to complete it. As the Company's CEO, I have gone on record saying that we intend for Solana to be the first of several large-scale central-station solar projects, and have set an ultimate goal of making Arizona the solar capital of the world. A credit downgrade to junk would devastate that vision.

Q. **HOW DO YOU RESPOND TO STAFF'S AND RUCO'S SUGGESTION THAT THE USE OF INTERIM RELIEF TO MITIGATE THE FINANCIAL HARM CAUSED BY REGULATORY LAG UNFAIRLY SHIFTS RISK FROM THE COMPANY TO RATEPAYERS?**

A. Such a suggestion is far off the mark. In the most simple terms, APS is entitled to rates that are sufficient to cover its operating and capital costs and provide a meaningful opportunity to earn a reasonable return on the fair value of its property. There is no legal or regulatory principle that requires the Company to forego this entitlement for **any** period of time – let alone a two year or longer period of regulatory lag.

The Company's current rates do not allow APS to recover its cost of service, nor have they for years. Mr. Smith concedes that, just since the end of the September 30, 2005 test year from APS's last rate case, APS has invested in at least half a billion dollars in ACC-jurisdictional rate base necessary to serve customers that is not reflected in the Company's present retail rates. *See* Smith Testimony at 12. For every additional day that APS is unable to recover these costs, the Company's financial condition worsens.

There is nothing unfair in requiring customers to pay for the Company's reasonable cost of service, nor can such a requirement be characterized as inappropriate "risk shifting." In fact, the opposite is true. For years, APS's shareholders have sacrificed expected and allowed returns while still contributing to the financial health of the Company through equity infusions. At the same time, APS's customers have received exceptional and reliable service at below-cost, shareholder-subsidized prices. Such an arrangement is simply not sustainable. The Company's financial condition grows more precarious, Pinnacle West's stock is selling for below book value and consistently performs worse than its peers, and APS relentlessly hangs on the edge of investment grade credit status, threatened with a downgrade to junk. The striking financial impact of the extensive regulatory lag that we are experiencing today must be addressed if APS is to avoid the threat of a credit rating downgrade and continue to meet its public service obligations in the future. Granting the Company's interim request is one important way in which the Commission can do so.

C. Staff's consultants' conclusion that APS's financial condition is currently strong enough not to require interim relief ignores the significant risks now facing the Company.

Q. HOW DO YOU RESPOND TO MR. SMITH'S SUGGESTION THAT "APS'S FINANCIAL CONDITION APPEARS TO BE SOUND ENOUGH TO NOT REQUIRE AN INTERIM INCREASE DURING THE PROCESSING OF ITS GENERAL RATE CASE" (*SEE* SMITH TESTIMONY AT 30)?

A. First, Mr. Smith's use of the qualifier "appears" should give the Commission pause, given the striking and undisputed consequences of his being wrong. Second, and despite Mr. Smith's and Mr. Parcell's belabored attempts to suggest otherwise, the evidence is clear that APS's financial condition is suffering from the impact of the extraordinary circumstances it now faces, that its ability to continue to invest in necessary capital projects is in jeopardy, and that it faces a substantial risk of downgrade during its general rate case proceedings without rate relief.

Staff's consultants fail to address the most fundamental issue – whether, absent interim relief, there is a reasonable risk that APS will be downgraded, be unable to secure needed capital, or be forced to forego needed and beneficial projects prior to the resolution of the Company's general rate case. Instead, Mr. Smith and Mr. Parcell engage in a lengthy and distracting discussion of how credit rating agencies rate utilities and a selective analysis of recent rating agency reports in an attempt to show that APS is **at the moment** sufficiently "sound" financially.

This argument appears to be premised on three factors: (1) that APS's debt is currently investment grade, *see* Smith Testimony at 23, 25; (2) that credit rating agencies have not indicated that interim relief is required to maintain that investment rating, *see* Smith Testimony at 25; and (3) that APS is not currently experiencing a financial crisis, Smith Testimony at 16. From this, Staff concludes that **"[u]nless there are unanticipated or unforeseen events that occur during that timeframe** . . . APS should be able to continue to provide safe, reasonable, and adequate service without an interim rate increase while the APS general rate case is being processed." *See* Smith Testimony at 15.

But that is not the standard for interim relief, nor should it be. Although APS's debt may currently be rated investment grade, the Company's credit metrics are such that the rating may fall to junk in the blink of an eye. And although APS currently has access to the debt capital markets, given the Company's financial condition and the current state of the debt markets, that access, too, may be denied on a moment's notice (as it has been in the past), and APS cannot meet all of its spending needs for the next several years with existing revolving credit agreements, as Mr. Smith appears to suggest it should. *See* Smith Testimony at 16, 28.

Prudent public policy requires keeping the state's largest utility in sufficient financial health at **all times** such that it has the financial wherewithal to overcome the financial challenges posed by any "unanticipated or unforeseen events" that may occur so that the highly negative consequences of such events can be avoided at the outset, rather than dealt with after the event occurs and it is too late to avoid the harm. Contrary to the suggestion of Staff's consultants, this means that the Commission must do more than simply examine the state of the Company's financial health as it exists at this very moment, but must look at the reasonable future risks facing APS to determine whether interim relief is appropriate. You do not wait to start building the ark until after you see the first drop of rain.

Q. WHY DO YOU BELIEVE IT IS MORE LIKELY THAN NOT THAT APS WILL LIKELY BE DOWNGRADED TO JUNK DURING THE COURSE OF THE COMPANY'S GENERAL RATE PROCEEDING?

A. I firmly believe that APS faces the significant threat of downgrade during the course of the Company's rate proceeding because it does not have sufficient revenue to sustain its FFO/Debt credit metric above investment-grade levels during the course of the Company's general rate case, much less any financial cushion to protect it from any financial difficulty that may occur during that time.

Irrespective of the admittedly general description outlined by S&P of what criteria a utility must maintain to remain within investment grade (a discussion that was overly simplified on pages 12 and 13 of Mr. Parcell's testimony), it remains true that – for a company with the regulatory and other challenges facing APS – the Company still must have an FFO/Debt ratio in the range of 18% to 20% in order to avoid a downgrade to junk. Although I agree with Staff that the FFO/Debt metric is not the "exclusive" metric analyzed by rating agencies (by describing it as 'key," I do not believe I ever suggested otherwise), it is indisputably the most important one – a fact that is commonly known in the industry and made clear by the very articles Mr. Smith cites in his testimony.

In the 2008 S&P publication describing "Corporate Ratings Criteria," attached to Mr. Smith's testimony at RCS-3, S&P plainly states that funds from operations is "the most frequently used credit measure in industrial ratings," and that cash flow adequacy analysis, usually the "single most critical aspect of credit rating decisions," "often focuses on levels of funds from operations (FFO)." *See id.* at 40-42. The Company's concentration on FFO/Debt is therefore most appropriate in attempting to discern generally when its credit metrics will be sufficiently low to make a downgrade a reality.

As APS has shown, even assuming an equity issuance of $400 million before year end 2009, the Company's FFO/Debt ratio will fall below the 18% threshold to junk just next year, resting at 17.6% by year end 2009 and 16.6% in 2010 under present rates – well outside of the parameters needed to sustain investment grade.

Q. PLEASE ADDRESS THE TABLE ON PAGE 20 OF MR. SMITH'S TESTIMONY, WHICH PURPORTS TO SHOW THAT APS'S FFO/DEBT RATIO WILL REMAIN AT INVESTMENT GRADE LEVELS WITHOUT INTERIM RELIEF.

A. Mr. Smith's attempt to use the data shown in the table on page 20 to prove that APS's FFO/Debt ratio can be sustained within investment grade levels even without interim relief is unpersuasive because it is based on a set of assumptions (which he expressly **required** in his data request) that are inherently implausible.

For example, the table assumes that APS will receive a base rate increase of anywhere from 9.5% to 17.5% on October 1, 2009. This assumption is shaky for a couple of reasons. First, it ignores the undisputed fact that APS rate cases have historically taken anywhere from 18-24 months to resolve, which would make any new rate that APS is granted in its permanent rate case effective in 2010, at the earliest. While APS hopes that the case will be resolved by October 1, 2009, as requested, it nonetheless questions whether it will benefit from permanent rate relief in this timeframe.

Moreover, the assumed level of rate increase is made without the benefit of *any* indication of what level of rate increase Staff, RUCO, or any of the other parties to the rate case (let alone the Administrative Law Judge or the Commission) will support. While the Company certainly hopes that it receives **at least** a 9.5% rate increase at the conclusion of its general rate case (and it needs much more, as that filing shows), Staff has made no such recommendation and it would be imprudent to **depend upon** any such level of relief for purposes of the interim proceeding before knowing what the analysis and recommendations of other parties will be.

The results in the table also assume that APS is able to receive an equity infusion from Pinnacle West under reasonable terms in 2008 – a virtual impossibility considering current timing, current market conditions and Pinnacle West's below-book-value stock price, not to mention the difficulty that Pinnacle West would have attracting equity investors on reasonable terms while APS is knee-deep in litigating a general rate case after having been denied interim relief (the premise of Staff's position) with a history of substantially underearning its allowed ROE by significant margins. These and other practical restraints that I will describe in detail below will likely prevent the Company from benefiting from any equity infusion before well into 2009, despite Mr. Smith's assumption to the contrary.

Give the likely unrealistic assumptions underpinning these results, Mr. Smith's analysis cannot be used as a basis for concluding that the Company's credit metrics are sufficiently sound without interim relief that it will be able to avoid a downgrade should interim relief not be granted.

Q. HOW DO YOU RESPOND TO STAFF'S CONSULTANTS' ARGUMENT THAT APS'S CURRENTLY "STABLE" OUTLOOKS PROVE THAT APS WILL NOT BE DOWNGRADED WITHOUT INTERIM RELIEF?

A. Staff's consultants attempt to use rating agency reports to undercut APS's claim that it will likely be downgraded prior to the conclusion of its general rate case misunderstands how rating agencies operate. As an initial matter, each of the "stable" outlooks published by the rating agencies anticipates constructive decisions in the Company's interim and general rate filings that will allow it to maintain its current investment grade levels. Moody's, for example, notes that its "stable" outlook for APS is specifically predicated on the expectation "that more balanced regulatory relief continues especially given that APS has several rate filings currently pending" (referring to both the interim and general rate matters). *See* Parcell Testimony, Attachment 8.

Similarly, the June 2008 S&P ratings report on which Mr. Smith and Mr. Parcell rely expressly notes that the Company's interim request was a consideration in that agency's "stable" outlook for APS, stating that "[t]he stable outlook reflects our expectation that consolidated cash flow volatility has been tamped down by the ACC's approval of a stronger PSA that speeds the recovery of fuel costs, but consolidated financial performance will continue to be challenged by regulatory lag at APS, which could be moderated by APS's pending interim rate request . . . . Ratings could be lowered to speculative [junk] grade if the company is not able to overcome the challenge of ensuring timely recovery of its prudently incurred costs through rate increases approved by the ACC." *See* Parcell Testimony, Attachment 9 at page 5. The fact that these "stable" outlooks specifically reflect the potential impact of the Company's interim filings undercuts the proposition that such outlooks conclusively demonstrate that "it is not imminent or probable that APS's debt will be downgraded to "junk" status if the $115 million interim rate increase is not granted." *See* Smith Testimony at 25.

Neither is there any merit to Staff's consultants' suggestion that a downgrade is not "imminent or probable" because credit rating agencies have not "announced that APS's debt would be downgraded if APS's request for interim rates were to be denied." *See* Smith Testimony at 25; Parcell Testimony at 12. As those experienced in the industry are well aware, credit rating agencies do not telegraph or otherwise expressly communicate to the utility or the public what specific impact a potential future event will have on that company's credit rating before the event occurs. A downgrade can happen in the blink of an eye, with no "announcement" or "warning" from the agency to the Company whatsoever. In fact, when S&P downgraded APS's debt from a "stable" BBB to BBB- in December of 2005, the Company did not learn that S&P had taken such action until I received a phone call from S&P's analyst an hour **after** the S&P ratings committee had already met and decided the issue.

Rather, what the Company has learned from the rating agencies – both through statements made in the reports cited above and from discussions with analysts – is that it is important that APS maintain an FFO/Debt ratio within **at least** the 18-20% range to stay within its current investment grade. For example, in conference calls that took place on July 22 and 25, 2008 between myself, APS's Senior Vice President and Chief Financial Officer, James Hatfield, APS's Vice President and Treasurer, Barbara Gomez, and Moody's personnel, Moody's specifically noted that APS's credit metrics needed to be in the upper part of the range applicable to APS and similar electric utilities because of what it believes to be Arizona's challenging regulatory environment. In a separate, in-person meeting between S&P representatives and Mr. Hatfield, Ms. Gomez, and me, held in S&P's San Francisco office on August 28, 2008, S&P expressly stated that it will be reevaluating the Company's credit status in its ratings committee after the Commission rules on APS's interim request. Together, these facts imply that if the Commission's decision in this matter deprives APS of the ability to keep its credit metrics within investment grade range, it faces the significant likelihood that APS's debt will be downgraded to junk status.

Neither does APS have any comfort in the fact that Moody's and Fitch currently rate APS two "notches" above junk grade, compared to S&P's one-level above junk credit rating, as Mr. Parcell suggests. *See* Parcell Testimony at 9, 17. As a practical matter, if any one of the three major credit rating agencies downgrades APS, the Company's debt will be regarded as junk by the market. Thus, if S&P downgrades APS to junk after taking the Company to its ratings committee following the resolution of this matter, APS and its customers will suffer essentially the same financial consequences that would have resulted had all three downgraded the Company's debt simultaneously. Moreover, any downgrade by one credit rating agency will likely cause others to reevaluate the Company's financial health and the reason for the downgrade under their own respective criteria, thus increasing the risk that more than one agency will revise the Company's ratings downward.

Q. PLEASE COMMENT ON STAFF'S CONCLUSION THAT THE VALUE LINE AND S&P STOCK EVALUATIONS CITED ON PAGE 14 OF MR. PARCELL'S TESTIMONY INDICATE THAT PINNACLE WEST'S "FINANCIAL STRENGTH AND VIABILITY" COMPARES FAVORABLY AGAINST OTHER ELECTRIC UTILITIES.

A. These services are fine for what they are, but their opinions simply cannot be used to support the point that Mr. Parcell attempts to make: that the Company's financial strength and viability are "below risk" compared to others in the **electric utility industry.**

Q. PLEASE ELABORATE.

A. Value Line and Standard & Poor's Equity Research each produce short reports on the stocks of **almost 2,000** companies of varying sizes and industries, not just those of the regulated electric utilities with whom Pinnacle West competes for equity investment. Value Line evaluates a universe of approximately 1,700 individual stocks, and each of its rankings is relative to all of the other stocks in Value Line's coverage universe, from small start-ups to Fortune 500 companies. Value Line determines its ratings by plugging historical data into computer models, with no independent research into the individual company at issue. Standard & Poor's Equity Research similarly ranks approximately 1,500 U.S. stocks, also using a computerized system. It stands to reason that, compared against a vast array of companies – many of which, because of their nature, experience tremendous daily and weekly fluctuations in stock value – regulated utilities with a relatively consistent revenue stream will generally rank well under such stock analyses as relatively stable investments. An electric utility is reasonably stable, for example, relative to a high tech company, a biotech company, or a recent Silicon Valley start-up IPO.

These rankings do not, however, reveal anything meaningful about the financial security of the individual company at issue, and thus cannot be used to suggest that APS is in a sound state of financial health or is not at risk of a ratings downgrade. Indeed, these stock evaluations are separate and distinct from credit rating analyses, a point made clear by Mr. Parcell's own exhibit, the S&P "Security Owner's Stock Guide" (attached to Mr. Parcell's testimony at Attachment 13), which notes that "[r]elative quality of bonds or other debt, that is, degrees of protection for principal and interest, called credit worthiness, cannot be applied to common stocks, and therefore rankings are not to be confused with bond quality ratings which are arrived at by a necessarily different approach." The stock evaluations on which Mr. Parcell relies thus cannot and do not support any intended implication that a credit rating agency will not downgrade APS because some stock analyst has classified Pinnacle West's stock as a "below average" risk relative to 1,700 other companies.

Neither, on their own, can these evaluations be used as "indicator[s] of financial strength and viability," as Mr. Parcell suggests. *See* Parcell Testimony at 14. In an attempt to support an overall conclusion that Pinnacle West is a "below risk electric utility holding company," Mr. Parcell cites three Value Line measurements – Safety, Beta, and Financial Strength – and one S&P Stock Ranking. *See* Parcell Testimony at 14-16. But as a close analysis of these rankings reveals, such a conclusion is simply inaccurate. I will take each listed ranking in turn.

According to Value Line, its "Safety" ranking is intended to measure, on a scale of one to five, the total risk of a company's stock relative to the approximately 1,700 other stocks in Value Line's coverage universe. As Mr. Parcell indicates, Pinnacle West's "Safety" ranking is a "2," not far from the 2.3 electric utility industry average. This ranking is determined by equally weighting two other rankings: Financial Strength and Price Stability. The Financial Strength rating, which Mr. Parcell separately identifies, attempts to evaluate and compare the relative financial strength of the broad range of companies whose stocks are reviewed by Value Line (using a "cash flow" analysis, though it provides little detail into its methodology). The relative ratings range from A++ (strongest) to C (weakest) in nine steps.

Although, as Mr. Parcell notes, APS is rated as an "A" in this regard – third of the nine levels – that rating is one that compares APS against a wide spectrum of industries, many of which have greater revenue and cash flow volatility compared to a regulated electric utility, and which thus may appropriately be deemed less financially strong for equity investment. The vast majority of the electric utilities in the Value Line investment survey fall closely together within the A to B+ range, with some few outliers scattered above and below. This measure thus shows little deviation between electric utilities and thus indicates little about how Pinnacle West's financial strength compares to that of its industry peers.

The second consideration in the "Safety" rating, the "Price Stability Factor" (which Mr. Parcell does **not** address), is intended to be "a relative ranking of the standard deviation of weekly percent change in the price of a stock over the past five years." The relatively high ranking of Pinnacle West and all other electric utilities in the Safety index is unsurprising given the emphasis on this factor. What the price stability analysis reflects is the fact that Pinnacle West's stock price has not varied significantly, **on a weekly basis**, over the past five years.

Stock values for regulated utilities seldom experience such short term price fluctuations, and would thus compare favorably against businesses in other industries that are at greater risk in this regard.

That is not to say, however, that Pinnacle West's stock has not fluctuated over the long-term. To the contrary: Pinnacle West's stock price per share has changed dramatically over the past several years, falling from a high of $51.67 on January 3, 2007 to a low of $30.26 on June 30, 2008 (below the book value per share of $37.22) – a 40% drop in stock price in just 18 months that equals a **$2.1 billion** loss of shareholder equity value and that has placed Pinnacle West's stock performance among the worst compared to others in the industry, as I have described.

As for the third Value Line category on which Mr. Parcell relies, "Beta," Value Line does not consider that category to be a "ranking" as much as a measure of stock volatility, attempting to capture how a particular stock price will move relative to the market as a whole. A stock with a beta of 1.0 is expected to move with the market over time. A stock with a beta greater than 1.0 is expected to rise or fall more than the market index. A stock with a beta lower than 1.0 is expected to be less volatile compared to the market index. There is thus little to be gleaned about Pinnacle West's "financial strength and viability" from Pinnacle West's Beta ranking of 0.80 compared to the electric utility industry average Beta of 0.87.

The last evaluation that Mr. Parcell cites is Standard & Poor's stock ranking of Pinnacle West as a "B+" – midrange on an eight point scale of A+ to D. This ranking, which attempts to capture the growth and stability of earnings and dividend record over the past 10 years, is almost certainly due to Pinnacle West's dividend per share growth and does not reflect APS's current "financial strength and viability," as Mr. Parcell erroneously suggests. As S&P explains, "[i]f a company pays a dividend on the common stock, it is highly unlikely that the rank will be below B-, even if it has incurred losses." *Standard & Poor's Quality Rankings: Portfolio Performance, Risk, and Fundamental Analysis*, October 2005, Standard & Poor's Corporation, c. 2005, p.5, found at http://www2.standardandpoors.com/spf/pdf/media/QualityRankingWhitePaperFinal.pdf.

As the Commission is aware, Pinnacle West restored its dividend at a low level in 1993 (after a three-year suspension) and grew it a modest $0.10 per share annually through 2006. As a result, its compound annual dividend growth rate from 1998 to 2007 was 5.8%. The average dividend growth rate for utilities that increased their dividends during that same time was 7.2%, demonstrating that these utilities increased their dividends by a greater margin than did Pinnacle West, even though starting from a higher base. When those utilities that did not increase their dividends are also considered, the dividend growth rate for the industry as a whole during this period was negative 0.2%. By the measure of dividend growth alone, Pinnacle West compares favorably to its industry peers. Indeed, given APS's massive underearning and its abysmal stock performance, Pinnacle West would have no chance of raising equity capital whatsoever, let alone on reasonable terms, if it terminated or reduced its dividends, nor would it have been ranked anywhere near a B+ under S&P's stock evaluation.

Given the narrow focus of S&P's rating of the Company's stock on dividend growth, such a ranking certainly cannot be used to suggest that the Company currently has sufficient financial strength to avoid the risk of credit downgrade during the course of the rate proceedings and the attendant inability to finance its necessary capital programs, nor can any of the other rankings to which Mr. Parcell refers. There is thus no merit to his conclusion that these evaluations show that APS's "financial strength and viability" compares well against others in the electric industry.

In fact, Mr. Parcell's conclusion is refuted by the following actual and undisputed facts: that, as a direct result of APS's poor financial health, Pinnacle West's stock is among the **worst performing** of all of the other investor-owned utilities with which Pinnacle West competes for equity capital, despite what any stock "risk" evaluation might be misread to suggest. As I noted in my Affidavit, APS's current financial condition has caused Pinnacle West's stock – which currently trades for below book value – to suffer a 19.5% drop in value during the three years ended April 30, 2008, while the electric utility industry as a whole experienced a 40.8% **increase** in stock value during this same period. *See* Brandt Affidavit at 8-9. Staff's consultants do not contest these facts, which put to rest any conclusion that Pinnacle West's stock is a "below average" risk for an electric utility or that APS's financial viability is somehow in better condition than the plain and undisputed evidence reveals. Their attempt to explain away these facts by focusing on stock evaluations that are virtually meaningless for the purpose of assessing the true state of APS's financial health is thus unpersuasive.

Q. HOW DO YOU RESPOND TO MR. SMITH'S SUGGESTION AT PAGES 21 TO 22 THAT INTERIM RELIEF IS NOT APPROPRIATE BECAUSE IT WILL NOT NECESSARILY PREVENT FUTURE DOWNGRADES OR CAUSE THE COMPANY'S DEBT TO BE UPGRADED?

A. I frankly do not understand Mr. Smith's suggestion that interim relief should be denied because it will not necessarily prevent a future downgrade. Essentially, Mr. Smith argues that APS should not be given the relief necessary to improve its credit metrics and provide it with an adequate buffer of protection against the risk of downgrade during the general rate proceedings because there may one day be an event of such magnitude that the Commission-provided buffer is insufficient and the Company is downgraded nevertheless. This is akin to arguing that a doctor should not treat a sick patient because that patient may be hit by a bus on the way home. While that may be true, it certainly should not be used as justification for failing to treat the patient to begin with.

As for the suggestion that interim relief should not be awarded because it will not result in a ratings upgrade, APS would welcome rate relief in a sufficient amount that its debt would be upgraded to higher credit levels. Indeed, that result is a key focus of the Company's plan for restoration of financial health, and would bring substantial benefits and long-term cost-savings to customers. But while interim relief is a necessary part of that plan – allowing APS to maintain current investment grade levels until its general rate case is resolved – the Company never intended for its interim request to result in a ratings upgrade. Nor is such a result required for interim relief to be appropriate. Just because the path to better financial health and higher credit ratings is slow and long, that does not mean the journey should not begin. The Company's interim rate request is an initial step in that journey.

D. Granting the Company's interim request will benefit customers and is in the public interest.

Q. MR. SMITH INDICATES THAT THE COMPANY HAS NOT SHOWN THAT THE INTERIM REQUEST WILL BENEFIT CUSTOMERS. PLEASE COMMENT.

A. I could not disagree more. The Company has shown that its current financial condition is such that it faces a serious risk of a downgrade to junk during the course of its general rate proceedings, and that – absent interim relief – it will be required either to bear the risk of a downgrade with no buffer to protect it against any added financial stress that may arise (with the attendant and undisputed ramifications on the Company and its customers, described in detail on page 13 of my Affidavit and conceded in Mr. Smith's testimony on pages 23-25 and Mr. Higgins's testimony on pages 3 to 4) or to forego projects that are either necessary for reliable service or that the Commission has otherwise deemed to be customer-beneficial and within the public interest. *See* Brandt Affidavit at 9, 13.

But even setting aside for a moment the substantial potential for downgrade, there is little question that the requested interim relief will improve the Company's earnings during the course of the general rate proceedings, which result itself will ultimately benefit customers. The belief that any action that inures to the benefit of shareholders must necessarily also be to the detriment of customers is simply wrong. The Company's ability to attract capital at reasonable prices such that it can provide reliable service and invest in customer-beneficial programs and sustainable technologies depends entirely upon its financial strength. The better APS's financial health, the lower the cost of capital that will ultimately be paid by customers to finance the projects from which they importantly benefit.

The converse is also true: the more the Commission artificially depresses electric prices in the short run, the worse the Company's financial health and the harder it will be for the Company to attract the capital it needs at reasonable prices. Equity capital invariably flows to where it can earn the best risk-adjusted returns, which means that the Company's *actual* rate of return is more important than its *allowed* rate of return. The better the Company's actual ROE, the better the terms on which the Company can issue equity. Because, as I have discussed, the Company's actual rate of return is significantly and negatively impacted by regulatory lag, any measure that reduces that impact and improves the Company's earnings will also improve the Company's chances of attracting needed capital at lower costs, thus keeping customer costs down in the long run. Because granting the Company's interim rate request will mitigate the impact of APS's extensive regulatory lag and improve the Company's ROE, it will also improve the Company's likelihood of being able to finance its necessary capital spending with a lower cost of capital, thus providing substantial benefits to customers.

IV. THE COMPANY'S PROPOSED AMOUNT OF INTERIM RELIEF WILL PROVIDE APS WITH A SUFFICIENT FINANCIAL CUSHION PENDING THE RESOLUTION OF THE GENERAL RATE CASE AND WILL BEST MEET IMPORTANT POLICY GOALS.

Q. HOW DID THE COMPANY CALCULATE ITS PROPOSED LEVEL OF INTERIM RELIEF?

A. The Company's proposed level of interim rate relief was not based on any analysis of what minimal level would be required to sustain the Company's credit ratings. Nor, contrary to Mr. Smith's suggestion, was it calculated in reference to the $1.7 billion that APS has expended in new facilities from the end of the Company's last Test Year through May, 2008 (a number that was mentioned only anecdotally in APS's Motion to illustrate the magnitude of the Company's capital spending obligations since its last Test Year). *See* Smith Testimony at 12. Rather, APS sought an interim base rate increase in the same amount of the roughly 4 mil 2007 PSA Adjustor that expired this past August in an effort to provide the Commission with the opportunity to implement the requested increase without any change in the amount of customer bills and to minimize rate volatility upon the conclusion of the Company's current general rate case.

Q. ASSUMING THAT THE COMMISSION FINDS THAT AN INTERIM RATE INCREASE IS WARRANTED, PLEASE EXPLAIN WHY THE $115 MILLION SOUGHT BY THE COMPANY IS AN APPROPRIATE AMOUNT.

A. Although the PSA Adjustor has now expired, the 4 mil figure remains an appropriate level of relief. Of the various amounts of relief suggested by the parties in this case, the Company's proposal provides the most reasonable level of protection for the Company against a ratings downgrade during the course of the general rate proceedings, generates an amount below what the Company is likely to receive under a conservative resolution of its general rate case and is thus not likely to require a refund. Also, if implemented in November of this year, the effective date of the increase can coincide with the rate **decrease** that most customers will experience in the November transition to winter rates, thus allowing the Commission to "phase-in" a significant portion of any increase resulting from the Company's general rate filing at a time when customers are likely to be impacted by it the least.

As an initial matter, there should be no dispute that some level of rate relief is appropriate to grant to APS at the conclusion of the general rate case. Both the AECC and Staff's consultants acknowledge in their Direct Testimonies that APS already has incurred legitimate capital costs that are not reflected in current rates, thus suggesting that the Company will receive some measure of rate relief when the permanent rate case is resolved. Even using what he refers to as a basic "non-controversial" analysis, Mr. Smith concludes that APS ultimately could demonstrate at least a $65 million increase in annualized revenue. The AECC proposes that an appropriate amount would be $42.4 million, effective January 1, 2009.

APS believes that a "non-controversial" analysis would actually support a much larger interim rate increase than the $115 million requested by the Company. In fact, as shown on Attachment DEB_RB-5, $115 million is not even in the upper range of the amount that justifiably could have been proposed.

I have summarized the analysis from Attachment DEB_RB-5 in the following table. Two adjustments to Mr. Smith's calculations are, at a minimum, necessary to fairly reflect the appropriate revenue requirement increase: the inclusion of book depreciation expense and consideration of the appropriate period. As to the former, Mr. Smith's revenue requirement analysis only considered a return "on" the "non-controversial" plant additions, and omitted the increased book depreciation that reflects the return "of" the investments in the revenue requirement. *See* Rebuttal Testimony of David Rumolo at pages 3-5.

Increased Revenue Requirements on ACC Jurisdictional Rate Base Growth

Period	Plant Additions	Plant Additions Including Rate Base Deductions	Revenue Requirement	Revenue Requirement On Increased Book Depreciation	Revenue Requirement Deficiency
	($M)	*($M)*	*($M)*	*($M)*	*($M)*
9/30/05 to 12/31/07	$1,114	$538	$65	$30	($95)
2008	$838	$401	$49	$23	($167)
2009	$907	$463	$56	$24	($247)

As this table shows, just including appropriate book depreciation on Mr. Smith's analysis results in a $95 million annual revenue requirement. But APS has made substantial ACC-jurisdictional investments since that time, and continues to do so. In 2008, it will have placed in service an additional **$838 million** of ACC-jurisdictional plant, bringing its cumulative annualized revenue requirement increase to **$167 million** using the same conservative analysis. By 2009, the same analysis on the additional projected **$907 million** dollars in gross ACC-jurisdictional plant additions brings the Company's annual revenue requirement increase to a cumulative total of **$247 million** – an amount that **more than doubles** the Company's requested $115 million level of relief. If the Commission finds it appropriate to use this type of non-controversial analysis as Mr. Smith suggests, APS would, of course, welcome any of the higher levels of relief that such an analysis can support. *See* also Rebuttal Testimony of David Rumolo at Attachment DJR_RB-1.

In addition to being a moderate request compared to what the Company might have otherwise proposed, of three alternatives presented by the parties, APS's proposal best provides the Company with a measure of protection from downgrade through the course of the general rate proceedings and meets the policy objectives described above. As I have previously explained, irrespective of any equity infusion by Pinnacle West[1], the Company's FFO/Debt ratio likely will fall below the 18% threshold of "junk" status in 2009, almost certainly before the Commission is able to reach a final decision in the pending general rate case – a fact of which rating agencies are acutely aware. Any interim relief granted should thus be sufficient in amount not just to keep APS teetering on the brink of junk, but to provide it with a level of protection against a ratings downgrade for as long as it takes for new rates in the general rate case to take effect. AECC Witness Kevin Higgins noted that "[i]n light of the cash flow pressures being experienced by APS, . . . some interim relief is warranted to protect retail customers from the negative consequences of a credit downgrade" and that "providing interim relief sufficient to allow APS to attain a 2009 FFO/Debt ratio of 18 percent, plus a reasonable buffer, during the pendency of its general rate case, is reasonable and in the public interest." *See* Higgins Testimony at 7.

While it is not possible to determine precisely what amount of rate relief will provide APS with a sufficient buffer to ensure the Company's ability to maintain its current financial metrics, continue to provide reliable service to customers, and prevent a ratings downgrade during the course of the general rate proceeding, the Company's proposal provides it with the most reasonable level of protection against such consequences. Under APS's proposal, the Company's FFO/Debt ratio would remain in investment grade through year-end 2009

[1] As discussed in Section V below, implementing the proposed $400 million equity infusion at the present time would not be in the Company's or the public's best interest and, in any event, would not minimize the need for the interim rate relief sought.

(19.6%), giving the Company a reasonable degree of cushion from downgrade until the FFO benefits from the general rate case decision can build (while still giving the Company some improvement in its ACC-jurisdictional earned rate of return on equity to 8.3% – still well below its currently allowed ROE of 10.75%), and phasing in a significant portion of the Company's general rate request at a time when customers are likely to be impacted by a rate increase the least.

Under the proposal of Staff's consultants, the Company's FFO/Debt is still just slightly above non-investment grade levels in 2009, at 18.7%, but falls again within junk range in 2010 at 17.8%. Similarly, AECC's proposed amount results in an FFO/Debt ratio of just 18.3% in 2009 and 17.4% in 2010. Though improved from the status quo, these credit metrics still leave APS teetering on the brink of junk throughout 2009 (and below that threshold in 2010) and thus do not provide the Company with virtually any layer of protection against any unanticipated event that may occur before new rates from the general rate case become effective. They also provide lower returns on equity compared to those generated by the Company's proposal, which makes it that much more difficult to attract new equity investors at reasonable terms. Moreover, because each of these amounts would naturally offset by a lesser amount whatever permanent rate increase is ultimately granted to the Company, these proposed alternatives do not as effectively address the policy benefits of most accurately reflecting the true cost of electric service on a current basis (thus sending appropriate price signals to customers) and phasing-in the impact of any final rate increase determined by the Commission in the general rate case.

Q. HOW DO YOU RESPOND TO MR. HIGGINS'S SUGGESTION THAT ANY INTERIM INCREASE SHOULD NOT TAKE EFFECT UNTIL JANUARY, 2009?

A. Delaying any rate increase until the start of 2009 would serve only to increase needlessly the risk of any negative action by the rating agencies and potential adverse impact of an unexpected event. Moreover, postponing the effective date of the interim increase beyond November of this year would deprive the Commission of the opportunity to implement the rate increase at the same time that most customers will experience a price decrease, thus moderating the financial impact of the interim relief on customers.

V. <u>TYING THE INTERIM RELIEF TO A REQUISITE EQUITY ISSUANCE IS CONTRARY TO THE PUBLIC INTEREST.</u>

Q. SHOULD ANY DECISION ON INTERIM RELIEF BE CONDITIONED, AS STAFF'S CONSULTANT HAS SUGGESTED, ON IMPLEMENTING THE PREVIOUSLY APPROVED $400 MILLION EQUITY INFUSION?

A. Absolutely not. Both practical and business implications make Mr. Smith's pre-condition unwise and counter-productive.

Q. WHAT ARE THE PRACTICAL IMPLICATIONS TO WHICH YOU REFER?

A. As an initial matter, it is highly unlikely that Pinnacle West would be able to issue equity by November 1, 2008, even in the event that it determined that it was appropriate to do so. Because of SEC disclosure rules that prevent an issuer from selling securities in the market when material news is pending, so called "blackout periods," (such as the announcement of quarterly earnings or the pending resolution of a significant regulatory matter), Pinnacle West is restricted from issuing stock from roughly October 10, 2008 until the release of the third quarter Report on Form 10-Q to the U.S. Securities and Exchange Commission in early November of this year, and then again in the early part of 2009. In addition, certain periods exist within the equity market when the ability to raise equity capital is virtually non-existent, including market holidays, anticipated significant Federal Reserve Bank actions, quarter-end and year-end periods, and the like. The upshot is that, between Pinnacle West's blackout periods and those where the market is inaccessible, it is unlikely that Pinnacle West would be able to issue equity and infuse it into APS before late March 2009 at the earliest. Postponing interim relief until that time further damages the Company's financial condition, makes a downgrade to junk all the more likely, and is thus against the public interest.

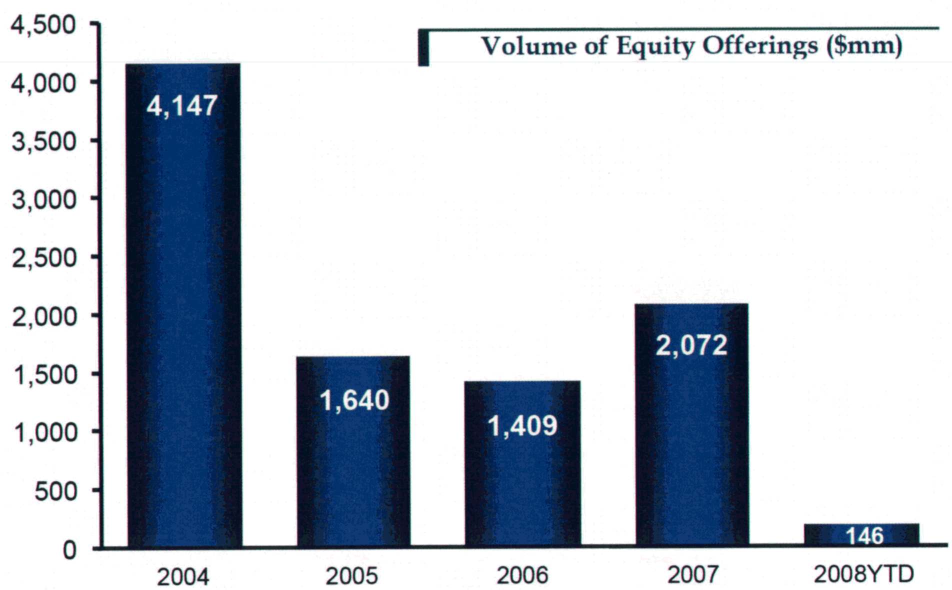
Q. WHAT ARE THE BUSINESS IMPLICATIONS TO WHICH YOU REFERRED?

A. A more significant reason why the grant of interim relief should not be conditioned on an equity infusion is that, between current market conditions and the Company's underperforming stock (which currently trades for below book value), attempting to issue equity before conditions improve would be foolish as a matter of both business practice and common sense. All companies, but in particular those in as precarious a financial condition as APS, must work to maintain an appropriate balance of equity, debt, and internal financing in light of then-existing market conditions. Given the unfavorable environment of current credit markets that are limiting financing options and the fact that the Company's stock price already is hovering at or below its book value, a condition requiring Pinnacle West to issue equity prior to or concurrent with the implementation of interim rates would be contrary to sound business and investment principles and would harm not only the Company's shareholders but its customers as well.

Q. DO YOU HAVE ANY EVIDENCE SUPPORTING YOUR CONTENTION THAT CURRENT MARKET CONDITIONS MAKE AN EQUITY ISSUANCE INAPPROPRIATE AT THIS TIME?

A. One needs only to review Wall Street Journal headlines over the past twelve months for evidence that the equity market is depressed and that all industries – not just electric utilities – are feeling the resulting impact. The specific impact of current market conditions on the willingness of electric utilities in particular to issue stock is well-exemplified by the following chart, which is based on the data provided to the Company by Merrill Lynch (one of the world's leading financial management and advisory firms) attached hereto at Attachment DEB_RB-6.

Integrated Utility Equity Issuance

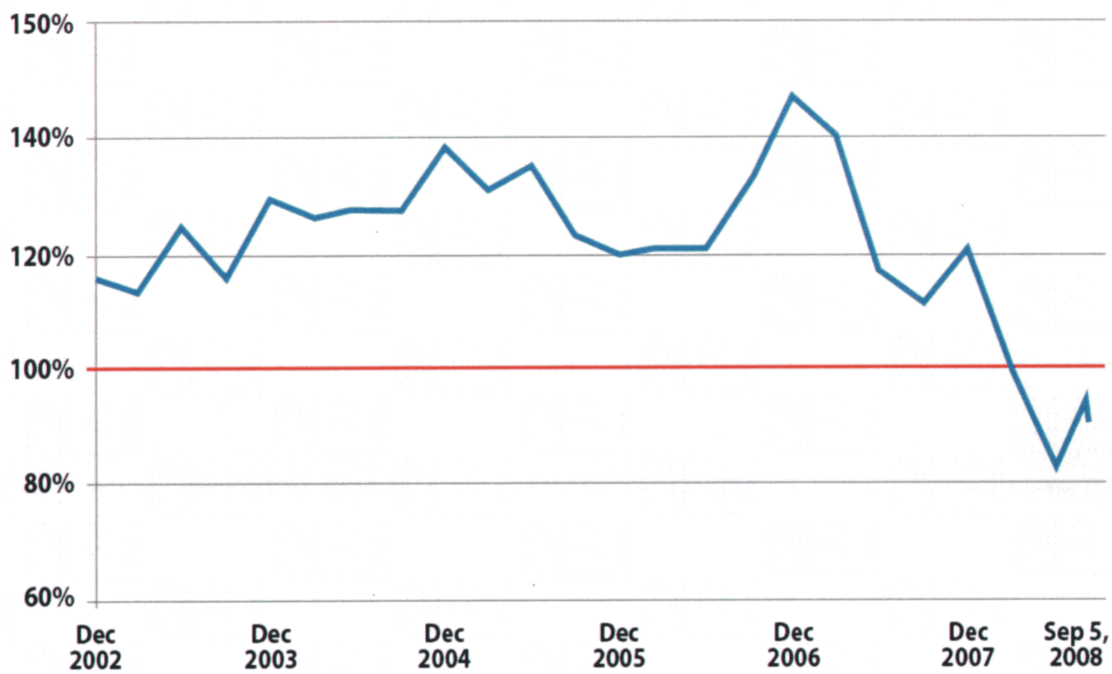


Source: Dealogic as of August 29, 2008. Includes utility and power equity & equity-linked offerings greater than $50 million in proceeds.

As this chart reveals, equity issuance transactions from integrated utilities have slowed considerably compared to what they were in 2004, and have all but stopped in 2008 (with only one such issuance being made to date this year). In 2004, the dollar volume of integrated utility equity offerings totaled $4.147 billion, falling to $1.64 billion in 2005, falling again to $1.409 billion in 2006, rising slightly to $2.072 billion in 2007 (an uptick resulting largely from a single, large offering of $615 million from Portland General Electric Company, resulting not from an ordinary equity issuance but from a sale out of the Enron bankruptcy), and then plummeting to just $146 million as of August 29, 2008. This data is compelling evidence that current market conditions have discouraged utilities nationwide from issuing equity in recent years.

For Pinnacle West in particular, any decision to issue equity in this volatile market would be especially detrimental in light of the fact that Pinnacle West's stock underperforms significantly compared both to the electric utilities against which it competes for equity capital, as I have previously discussed, and against its own past performance – an underperformance that is entirely attributable to the distressed financial condition of Pinnacle West's primary subsidiary, APS. In fact, as the following graph shows, Pinnacle West's stock is currently trading far below book value and has been for some months:

Pinnacle West Market-to-Book Value
December 31, 2002 – September 5, 2008



It is universally recognized that selling stock below book value means that a company is selling its shares for less than the value of those shares to existing shareholders, thus diluting the existing shareholders' investment and making it difficult to attract new investors. In addition, such an act sends a signal to the financial world that the Company does not believe its precarious financial condition will improve, thus further depreciating stock value and making the Company's ability to attract equity capital all but impossible. Moreover, because equity capital is more expensive than debt, and does not have a corresponding tax deduction, as does interest on debt, it increases the Company's overall cost of capital and is often the last tool in the toolbox to which the Company turns to meet its financing needs.

In the equity infusion docket, APS requested and was authorized to receive an equity infusion of "up to $400 million." The use of the words "up to" was an important caveat, because the Company intended to use only as much equity as was necessary and appropriate to strategically finance its capital program. Assuming the Company decided to issue the full $400 million (the amount that Mr. Smith would require here), the Company's future revenue requirement – and thus the future cost to customers – would increase by at least $40 million annually. Moreover, under current conditions, any equity issuance that Pinnacle West might be able to make would almost certainly be on unreasonable terms, thus increasing capital costs further. In the best of market conditions, newly issued common stock rarely sells for the last traded price before the sale, but is typically discounted in the range of 1% to 3%. Sales in a difficult market and under distressed circumstances result in discounts that are substantially greater. Equity issuances are one of the most important matters that companies and boards of directors face, and, as CEO of APS, I could not reasonably recommend to our Board of Directors that we make an equity offering under such conditions.

Staff's consultant's condition also assumes that Pinnacle West would be able to issue equity at all in the near term, which may not be possible – a point recently underscored by Daniel Ford of Lehman Brothers Equity Research, the preeminent Wall Street electric utility analyst, who, in commenting on Staff's filed testimony in this matter, noted that "[w]e view the $400 million equity infusion as difficult to meet given the current environment for equities, and specifically given that PNW's equity is currently trading below book value."

See Lehman Brothers Equity Research Company Update on Pinnacle West Capital, September 2, 2008, attached hereto at Attachment DEB_RB-7.

Equity issuances can be a necessary and beneficial form of financing, and the Company should continue to be allowed the flexibility to use them as strategically appropriate. Nevertheless, it is hardly within the public interest to pre-condition otherwise necessary interim relief on such issuances if the associated costs can be avoided. To whatever extent the Commission and the Company can bolster APS's financial health without forcing Pinnacle West to issue equity under current market conditions, good business practice and public policy strongly suggests they should do so. This is particularly true in light of the fact that the data and analysis supporting the Company's request for interim relief already assume and incorporate any benefit from such infusion, and thus the additional equity would not alleviate the pressing need for immediate assistance from the Commission.

Q. MR. SMITH APPEARS TO SUGGEST ON PAGE 40 OF HIS TESTIMONY THAT, IN APPROVING THE COMPANY'S EQUITY INFUSION APPLICATION, THE COMMISSION SOMEHOW REQUIRED THE EQUITY INFUSION TO OCCUR. HOW DO YOU RESPOND?

A. That Decision simply granted Pinnacle West the authority to issue equity and infuse it into APS in the event that Pinnacle West "determines that it would be strategically advantageous to do so." *See* Pinnacle West's Notice of Reorganization in Docket No. E-01345A-08-0228. *Cf.* Decision No. 70454 at Pages 3-4 (finding as fact that its authorization would allow APS to issue equity capital "in recognition of the broader economic conditions" and incorporating in its first ordering paragraph all of the terms "set forth in the application.")

In granting the Company's request, the Commission considered and approved an amendment to the application that extended the authorization through December 31, 2009. *Id.* As the discussion at the open meeting in that matter made clear, the Commission approved that amendment in order to give Pinnacle West the flexibility it needed to issue equity when the timing was right, consistent with sound business practice and in light of the Company's underperforming stock value and depressed market conditions. Mr. Smith's attempt to use that approval now as a means to require the Company to issue equity before market conditions improve and Pinnacle West determines that the timing is appropriate undermines the very flexibility that the Commission found desirable in granting that authorization and must therefore be rejected.

Although the Company believes that it was and still is critical to preserve its ability to issue additional equity, it is clear that actually issuing such equity at this time would only exacerbate the Company's delicate financial condition and would weaken the Company's financial structure in the long-term. There simply is no valid reason to tie the propriety of interim rate relief to an action that will not impact the required amount of such relief or otherwise benefit the Company or its customers. Just as the Company must continually evaluate its current circumstances to determine the necessary level of capital expenditures and best financing options, so too should the Commission consider all pertinent factors in deciding how the Company may best address its needs. Mr. Smith's recommendation does not do so.

VI. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS TO YOUR REBUTTAL TESTIMONY?

A. Yes. APS envisions a bright and innovative energy future for Arizona – one in which APS not only continues to do its job of supplying reliable electric service for the State's growing demand, but that also fosters a sustainable environment and reflects the benefits of high quality customer service and investment in new customer-friendly and energy-efficient technologies. APS hopes and believes that the Commission shares these important goals.

But the Company's ability to make these investments and sustain reliable customer service depends entirely upon APS's financial strength, which in turn requires timely and supportive regulatory treatment. Today, Arizona's extensive period of regulatory lag, coupled with the Company's extraordinary spending requirements, has had a destructive impact on APS's financial condition and has substantially increased the risk that APS's credit rating will be downgraded to junk – a risk that Staff and RUCO both understate and under-appreciate, with potentially devastating (and undisputed) consequences.

These are the very types of "special circumstances" that justify the granting of interim relief. Neither the Company nor the Commission should allow the view of what is "normal" or "traditional" to stand in the way of equipping APS with the means to provide reliable service to its more than one million customers and to implement progressive and innovative energy policies that are imperative to the sustainability of our State's energy future.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

UTILITY FOCUS

March 14, 2008

PINNACLE WEST CAPITAL (PNW)

Overview

PNW's principal subsidiary Arizona Public Service (APS) is one of the fastest growing electric utilities in the U.S. APS' customer growth in 2007 was 3.3%, and averaged about 4% during the years 2005 through 2007. In mid-2007, APS received a decision from the Arizona Corporation Commission (ACC) in a long-standing electric rate case that contained several positive aspects. However, the proceeding was decided about 20 months after the case was filed -- we note that the extent and consistency of the exorbitant regulatory lag in Arizona is without comparison in the industry. APS is expected to file a new base rate case within the next few weeks -- we believe that such a proceeding would not be decided until at least the fall of 2009. The upfront costs associated with customer growth, combined with the length of time it takes to complete a general rate case in Arizona, is clearly a source of long-term earnings attrition. PNW's earnings from continuing operations have fallen in each of the last two years and the company has earned a single-digit return on equity since 2003.

In addition to APS, which accounted for about 92% of consolidated income in calendar 2007, PNW's businesses include real estate development conducted by subsidiary SunCor (4% of consolidated income) and marketing and trading operations and energy-related investments (about 4%). PNW did not raise its dividend in 2007, thus ending its streak of dividend increases at 13 straight years. In terms of stock price performance relative to the industry, the PNW shares underperformed significantly in 2007, falling 16% versus a roughly 10% average stock price for companies in the RRA Index. This underperformance has continued into 2008; year-to-date, the PNW share price has fallen about 18%, compared to 11% drop in our index.

Pricing Informtaion	
Closing Price	$34.95
Date of Closing Price	03/13/08
Shares Outstanding (Shares)	100,499,104
Outstanding as of:	02/21/08
Market Capitalization ($M)	3,512.44
Total Enterprise Value ($M)	7,087.70
Market/Book	99%
Return on Equity	8.60%

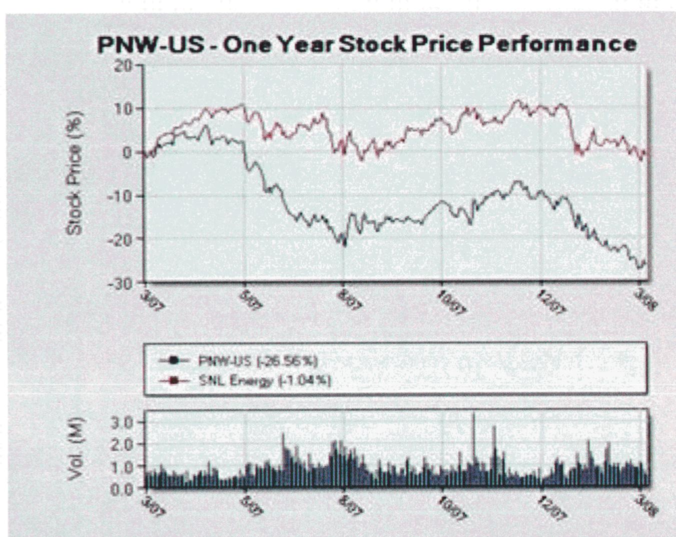
Credit Ratings	
S&P Senior Unsecured Rating	BBB-
S&P Senior Unsecured Date	06/28/2007
Moody's Senior Unsecured Rating	Baa2
Moody's Senior Unsecured Date	04/27/2006
Fitch Senior Unsecured Rating	BBB-
Fitch Senior Unsecured Date	12/21/2007

Year	* EPS	P/E Ratios
2006	$3.10	--
2007	$2.98	11.7x
2008E	$2.65	13.1x
2009E	$2.70	12.9x

Rate	Dividend Yield	Payout
$2.10	6.04%	71%

* EPS Adjustments shown on last page.

* Senior unsecured ratings of Arizona Public service co is shown since the ratings for the holding company are not available.



Regulated Operations

Arizona's electric industry is considered to be restructured, given that retail access is permitted; however, there are no competitive retail suppliers in the state, and the ACC continues to regulate the utilities' in-house generation under a traditional rate-of-return/rate base regime. APS' most recent case was decided in June 2007 – the ACC granted the company a $322 million (15%) rate increase, effective July 1, 2007, based upon an above-industry-average 10.75% ROE and a $4.4 billion original-cost rate base. While this was a relatively significant rate hike in percentage terms, we note that the case was based upon a very stale test year (12 months ended Sept 30, 2005) that concluded almost two years prior to the date of decision. This, as well as some of the restrictive adjustments adopted by the ACC, has made it difficult for APS to earn the ROE authorized in the case.

Positive aspects of the ACC's rate decision included the authorization of a significant interim power cost rate increase on May 2, 2006. This increase was supposed to be in effect until year-end 2006, but the Commission ultimately extended the emergency increase beyond that date when it became evident that the case was not going to be decided by that time. Additionally, the ACC removed the lion's share of the restrictive limitations that had been placed on APS power supply adjustor (PSA) in the company's previous rate proceeding. Specifically, the Commission: removed the $776.2 million total PSA recovery cap; eliminated the 4-mil "lifetime" on the annual PSA adjustor, replacing it with a 4-mil "annual" cap; added a "forward" component to the adjustor; and, eliminated the requirement that a PSA surcharge application be filed whenever the deferral balance reached $100 million. However, the ACC retained the 90/10 sharing mechanism, whereby the company absorbs 10% of fuel and purchased power costs that are in excess of the amount reflected in base rates.

Another issue that was considered in the rate case pertained to the costs incurred during the 2005 Palo Verde outages. The ACC disallowed costs of about $14 million, including accrued interest ($8 million net-of-tax), and approved the recovery of the balance (roughly $34 million, including accrued interest) through a temporary PSA surcharge over the 12 months through June 30, 2008. This increase was in addition to the base rate hike noted above.

More recently, on Feb. 13, 2008, the ACC ordered APS to account for residential line-extension fees as contribution-in-aid-of-construction (CIAC) rather than revenue. We believe that the Commission intends to revisit this issue in the future, most likely in the context of APS' next rate case. This issue relates to a new tariff for "growth" customers who require a line extension for newly constructed homes. Prior to this ruling, such customers were granted a "free footage" line extension allowance. The ACC approved APS' proposal to charge line-extension customers a fee equal to the total estimated construction costs; however, the Commission denied the company's proposal that the new tariff be classified as revenue that can be used as a dollar-for-dollar offset to mitigate future rate increases for all other customers, and instead ordered the fees to be classified as CIAC. The company had indicated that its proposed treatment was consistent with the ACC's contention that growth customers should pay at least a portion of the higher costs that would otherwise be imposed on all APS customers. Accounting for these fees as CIAC will provide an increase in cash flow, but will have no impact on revenue. In APS' next rate case, the CIAC will be used to reduce rate base, thus offering only a limited downward effect on all other customer rates.

Additionally on Feb. 13, the ACC approved APS' request to implement a $30 million increase, subject to refund effective March 1, through a transmission cost adjustor. The increase was equal to that approved by the Federal Energy Regulatory Commission (FERC), also subject to refund, pending the FERC's final decision in an APS transmission rate case. It is our understanding that settlement discussions are ongoing in the FERC proceeding. We note that the FERC approved APS' request to implement a $37 million transmission rate increase, subject to refund, with $30 million allocated to the Arizona jurisdiction and $7 million to wholesale transactions. The $37 million increase is based upon an 11.3% ROE and a calendar-2006 test year.

As previously noted, APS is expected to file a new rate case in the very near future. Assuming that the ACC adheres to its unfavorable practice of deciding rate cases within a 15-20 month time frame, this next proceeding would be decided in the fall of 2009. We note that late 2009 appears to be a period that will be free of gubernatorial or commissioner elections, factors that can delay or negatively affect the outcome of a major rate proceeding. By that time, the ACC will have three new members, as Chairman Mike Gleason and Commissioners William Mundell and Jeff Hatch-Miller, all Republicans, are term-limited and cannot run for re-election. Elections for these four-year terms will take place in November 2008. The other two commissioners, Kristin Mayes and Gary Pierce are serving terms that extend to January 2011.

Earnings and Finances

PNW's per share earnings from continuing operations in 2007 were $2.98 versus $3.10 in 2006. EPS were negatively impacted by: a slowdown in sales of homes and land at Suncor due to conditions in the western U.S. real estate market, $(0.37); higher generation operations and maintenance expenses, including overhauls and a Palo Verde performance improvement plan, $(0.26); and, higher depreciation and interest associated with increased capitalized plant balances, $(0.17). These negatives were partially offset by: retail sales growth, $0.28; favorable weather, $0.23; and, the impact of the mid-year rate increase decision, $0.13.

For 2008, our $2.55 EPS estimate is within the guidance range provided by the company, and reflects the following earnings-reducing factors: normal weather; the absence of a 2007 prior-period tax adjustment; the mid-2008 expiration of a power sales contract; slightly lower income from Suncor; and, increased O&M, depreciation, taxes, etc., associated with service territory growth. These factors are to be partially offset by the full-year effect of the 2007 ACC rate decision; the March 1, 2008 implementation of increased transmission rates; and, continued customer growth, albeit at a lower rate (APS forecasts customer and sales growth to approximate 1-2% during the years 2008 through 2010).

PNW's capital expenditures for the years 2008 through 2010 are estimated at about $3.74 billion, spread fairly evenly over the period. More than one-half of this amount is targeted for APS delivery operations (infrastructure additions, upgrades, and replacements, new customer construction and related information systems), and about 30% targeted for generation (primarily additions, upgrades, and replacements of various plant equipment -- turbines, boilers, and environmental equipment). Most of the remaining cap ex is related to investments at SunCor. The lion's share of the forecasted cap ex is expected to be financed internally; however, the company expects to issue both debt and equity during the year. PNW last issued common stock in 2005, and at year-end 2007 its equity ratio approximated 49%. Currently, APS' senior unsecured bonds are rated BBB- by Standard & Poor's, Baa2 by Moody's, and BBB by Fitch.

We note that in 2006, the ACC increased the state's renewable resource requirements, whereby the utilities will be required to supply 15% of retail energy sold from renewables by 2025. The ACC also required distributed generation to comprise 5% of the renewables portfolio beginning in 2007, with this percentage to increase to 30% by 2012. In connection with these standards, in February 2008, APS entered into a 30-year contract to purchase the energy and related emissions credits from a 280-MW solar power plant that is expected to go into commercial operation in 2011. The completion of this plant, by Abengoa, a Spanish company, is dependent upon the extension of certain federal tax credits.

RRA Evaluation: While Arizona's regulatory climate has improved somewhat over the past few years from the standpoint of more constructive treatment of rate case issues, the rate case process continues to be unnecessarily laborious and contentious, and politically driven. It took the ACC a total of almost four years to decide the last two APS rate cases – certainly not optimum conditions for a high-growth utility to operate under. Additionally, regulators have not given any indication that the next rate case for APS will be decided in a shorter time frame. Cash flow has improved with the relative stabilization of fuel prices, the operation of the PSA, and the mid-2007 rate case decision. PNW's unrecovered fuel and purchased power deferral balance has declined; at year-end 2007, the balance was $111 million, down from $160 million at year-end 2006. Given its stagnant earnings trend, PNW did not raise its dividend in 2007 after 13 straight years of increases, and its stock performance over the past several months has resulted in a dividend yield that is one of the highest in the RRA Index. On the basis of our estimate for 2008, PNW is trading at a small discount to the group, a level we view as appropriate given the regulatory issues that this company continues to face. We are continuing our "Hold" recommendation on the PNW shares. (Previous Report: 6/8/07)

Robert Schain

FEDERAL ENERGY REGULATORY COMMISSION

NEWS

June 19, 2008

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Mary O'Driscoll - 202.502.8680

FERC Examines Causes of, Responses to Rising Electricity Costs

Higher fuel prices, increased capital costs and continued uncertainty about climate policy are helping fuel the rising costs of electricity faced by consumers across the country, the Federal Energy Regulatory Commission (FERC) said today.

The rising cost trends are likely to continue for years, according to a report presented to the Commission by analysts from FERC's Office of Enforcement. The report pegs current futures prices for natural gas at $2.50 to $5 above the average 2007 spot price for natural gas, and costs for everything from iron and steel to cement and copper wire rising significantly over the past several years. Those have contributed to increases in the cost of new generation for every type of power plant, from nuclear power to combustion turbine and wind generators.

"FERC regulatory policy must be based on reality, and that sobering reality is that the upward pressure on electricity prices – higher capital costs for new power plants, higher construction costs, and higher fuel costs – should continue for some time," FERC Chairman Joseph T. Kelliher said. "That means electricity prices will be higher than many Americans would like."

"We must confront three realities: FERC is regulating in a high-cost environment; the United States needs massive investments in new electricity generation, transmission and distribution facilities; and we are beginning to confront the climate change challenge, which puts us in a period of uncertainty regarding policy," Kelliher added. "There is tension among these three realities, and they work at cross purposes. The United States cannot simultaneously make the massive investments necessary to assure security of our electricity supply, make additional large investments to confront climate change, and lower electricity prices. Doing so would likely result in failure."

The report says that consumers and the market likely will respond with demand response measures that help reduce energy consumption during times of peak prices, energy efficiency and conservation measures, and technological innovations that could usher in changes that help reduce costs and improve value, as they did in other competitive industries such as telecommunications.

The FERC staff report, "Increasing Costs in Electric Markets," is available on the FERC website, www.ferc.gov.

(30)

R-08-43

FEDERAL ENERGY REGULATORY COMMISSION

June 19, 2008
Item Nos. A-3

Chairman Joseph T. Kelliher

Statement of Chairman Joseph T. Kelliher on Cost of Electric Generation Staff Presentation

"I thank the staff for the presentation, which highlights some of the hard realities that FERC is confronting, and that are guiding the development of FERC regulatory policy. I think it is important that these hard realities be better understood by the general public and others.

FERC regulatory policy must be based on reality. The reality is that upward pressure on electricity prices - higher capital costs for new power plants, higher construction costs, and higher fuel costs - will continue for some time. That means electricity prices will be higher than many Americans would like.

We are actually confronting three realities. First, FERC and state commissions are regulating in a high-cost environment - that is not likely to change soon. Second, the U.S. needs massive investments in new electricity generation, transmission, and distribution. Third, we are beginning to confront climate change challenge, and are in period of uncertainty regarding policy. Acting on climate change will come at a significant cost - not necessarily an unreasonable cost.

There is tension among these three realities - they work at cross purposes. FERC has regulatory policies designed to encourage investments in generation and transmission. These policies have been criticized because they have some impact on cost. New coal generation has been cancelled due to climate change uncertainty, reflecting the tension between security of electricity supply and climate change.

We must accept the U.S. cannot make the massive investments necessary to assure security of our electricity supply, make additional large investments to confront climate change, and lower electricity prices at the same time. If we try to do all three, the result will likely be failure.

What can we do about price? We cannot change cost fundamentals, either for power plant costs or fuel costs. Coal prices and the costs of construction materials are set in a world market. Natural gas prices are still set on regional basis, reflecting North American market fundamentals.

The U.S. can improve energy efficiency and demand response, and FERC is acting in these areas, benefiting from the leadership of Commissioner Wellinghoff.

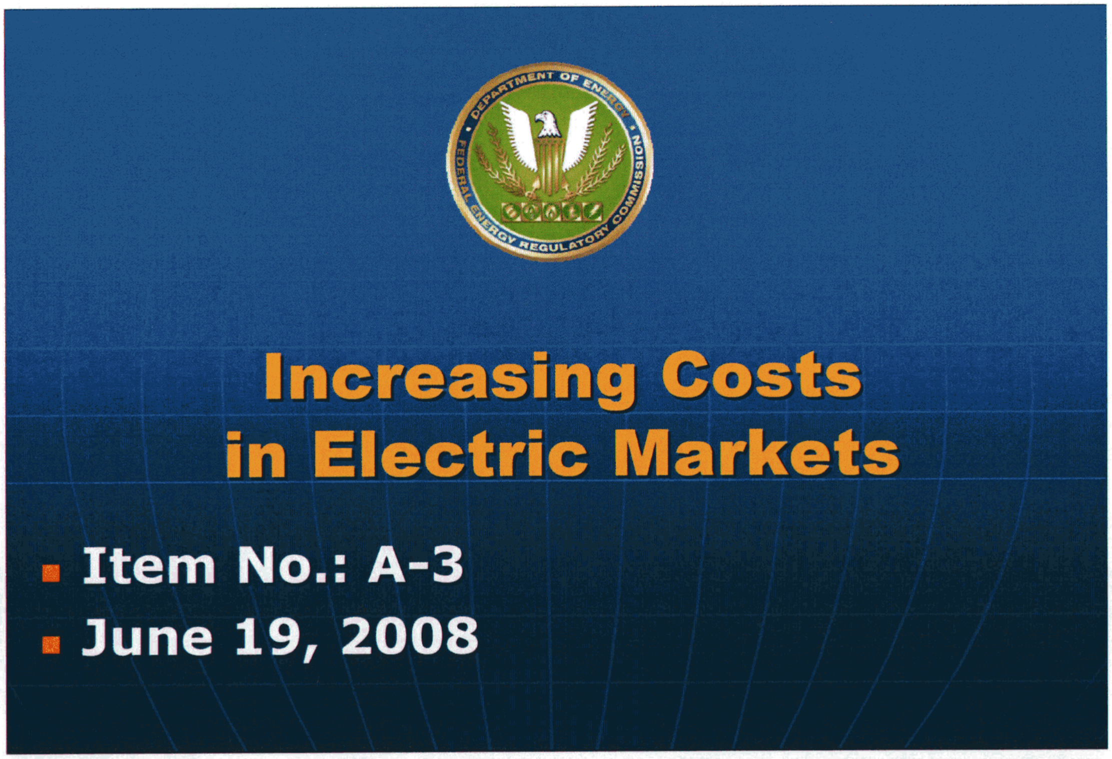
We can make sure that when power plants are built, they are built in a way where competitive pressures govern cost both construction cost and operating costs. There is more than one path to support new generation, and some paths more likely than others to produce lower cost electricity.

We can make sure prices are not a product of market manipulation or market power exercise. FERC's duty is to assure that wholesale electricity prices are just and reasonable. That means prices that are high enough to support continued investment in new electricity supply, environmental mitigation, and improved delivery across transmission and distribution lines.

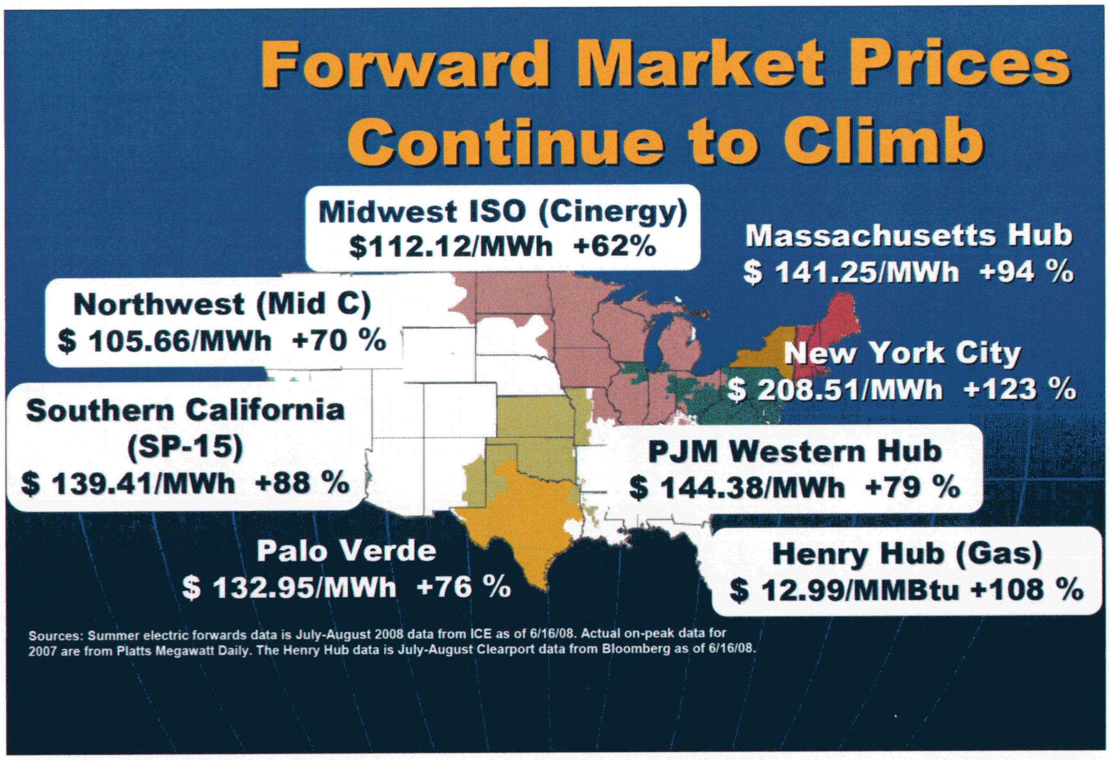
We recognize the risks of market manipulation may be greater in a high-cost environment, and we will remain vigilant to assure the wholesale prices reflect market fundamentals, rather than manipulation. We can assure wholesale power prices do not rise any higher than they have to in order to assure security of our electricity supply and meet the climate change challenge.

The last time we were in a high-cost environment similar to this was the late 1970s and early 1980s. Back then, the high-cost environment was the product of traditional rate regulation. Competition policy was created as a direct response to the failure of regulation.

Competition policy was rooted in the conviction that competition does a better job controlling costs than regulation, that competition does a better job developing and deploying new technologies, that competition does a better job improving operating performance, and competition properly shifts risk from consumer to market participants. Those truths still apply today, and competition policy is best suited to address the hard realities we are confronting today."

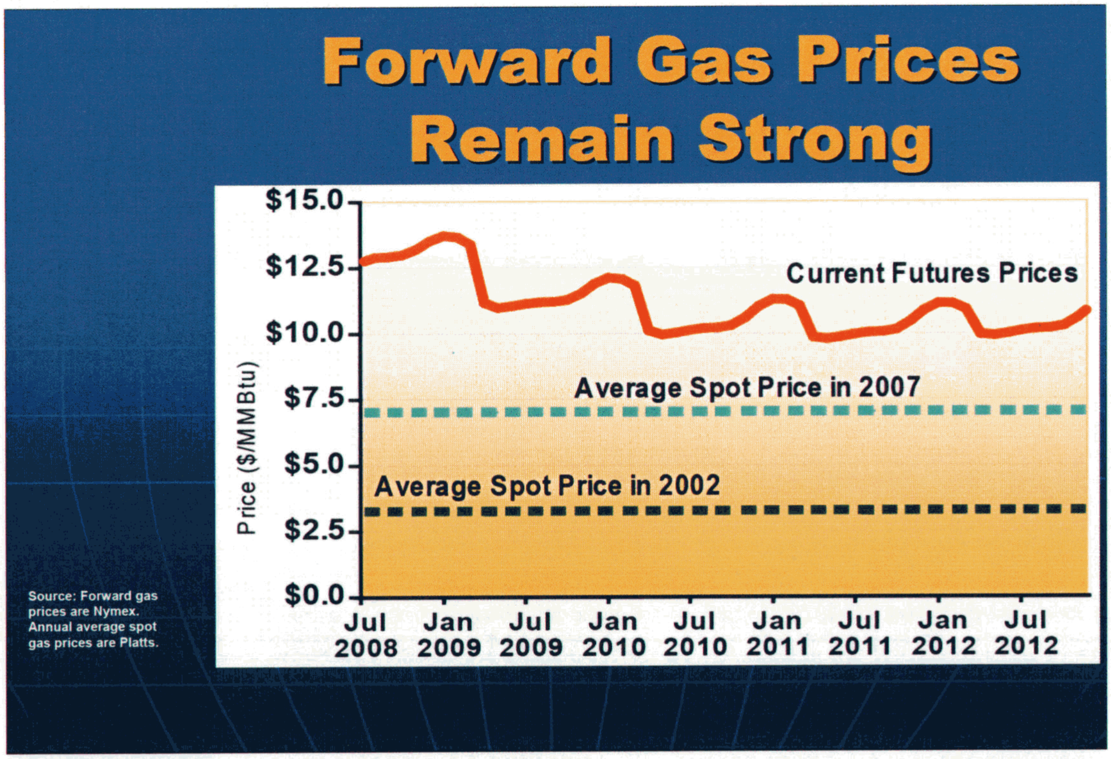


Mr. Chairman and Commissioners, good morning. I am here to present the Office of Enforcement's assessment of likely electricity costs in coming years. This presentation will be posted on the Commission's Web site today.

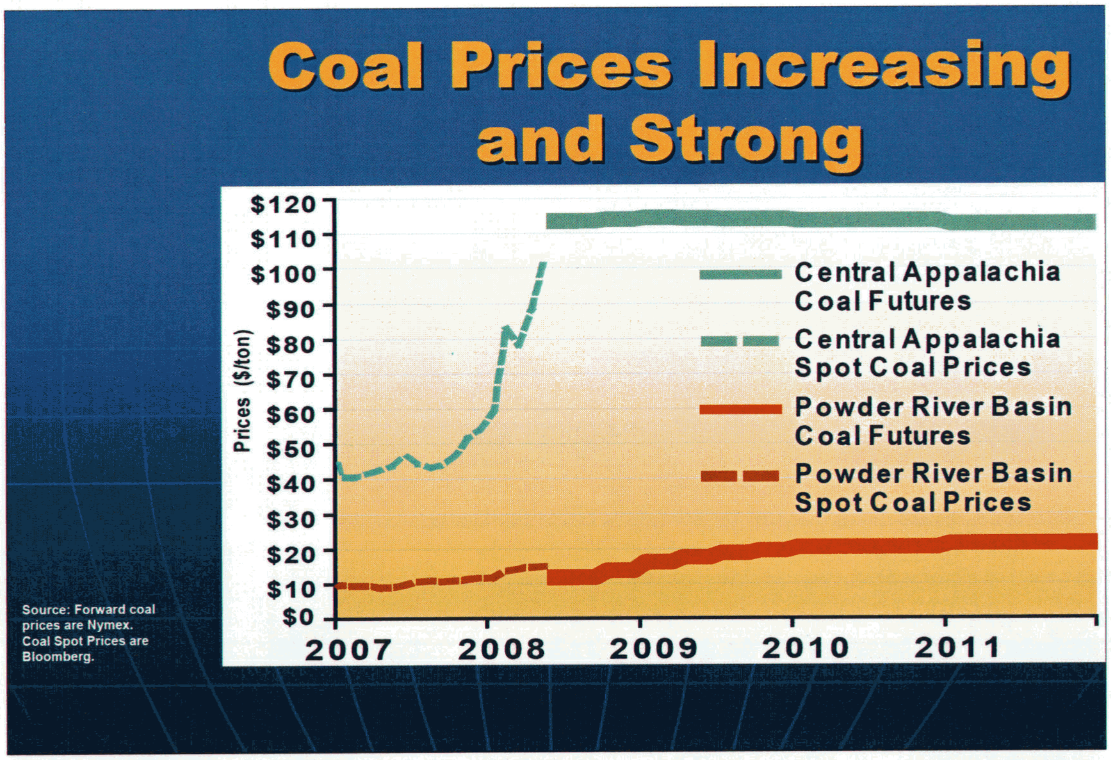


At last month's meeting, we reported that forward market prices for electric power are much higher than the prices we actually experienced last year. This trend is universal around the country. The slide shows the increases in forward prices for July and August as of this week. They have risen further during the last month as natural gas prices have continued to rise.

There is little reason to believe that this summer is unusual. Rather, it may be the beginning of significantly higher power prices that will last for years. The purpose of this presentation is to explain why that is so. The two major factors pushing the costs of electric generation higher are increased fuel costs and increased cost for new construction. These factors affect all parts of the country. That is, higher future prices are likely to affect all regions.



The primary reason for the electric power price increases this year is high fuel prices. All current market indications suggest that they will remain high. Let's look at natural gas, which often determines prices because it is so frequently on the margin. The slide shows futures prices for the next few years. The futures prices are somewhat lower for 2009 than for 2008. Even so, they are a good deal higher for all years than the prices people actually paid last year, and they are much higher than the prices many of us remember from earlier in the decade. The implication is that markets anticipate continuing high prices, even though they know that the United States has seen a significant increase in domestic natural gas production over the last year and a half. The anticipation of further high prices makes more sense when one considers the likely increase in gas demand for generation and the global nature of competition for LNG.



Natural gas is not the only important fuel in setting electric power prices. Coal still powers half of all power produced in the U.S. In some markets – the Midwest and the Southeast, for example – coal is often on the margin and plays a major role in setting average prices over time. The slide shows that the price of one key form of coal – Central Appalachian coal - has risen rapidly over the last year. Forward markets show continuing high prices for Central Appalachian coal for the next three years. This reflects, in part, the growing global market for coal and the relatively weak US dollar. Coal imports are becoming more costly and coal exports more profitable, both of which contribute to higher prices in the United States.

I should mention that other coal prices behave somewhat differently from Central Appalachian coal. For example, a majority of the overall cost for Powder River Basin coal comes from transportation rates and can be more difficult to see. Nonetheless, the implication of the prices we can see is that electric power prices are likely to increase even where coal is on the margin. This may take place somewhat differently from the way natural gas price increases flow through into power prices. Generally, companies buy coal under fairly long term contracts, so there may be a lag before the higher prices show their full effects. But the effects are coming.

Net Natural Gas Generation by Region
(TWh)

Region	2000	2007	Difference
Northeast	66.3	103.9	37.6
RFC	41.0	64.5	23.5
SERC	86.9	150.5	63.6
FRCC	42.0	96.7	54.7
ERCOT	155.9	163.3	7.4
Midwest	44.2	62.8	18.5
WECC-Rockies and SW	28.1	77.6	49.5
WECC-CA and NW	115.4	129.7	14.4

Source: Derived from Energy Velocity (differences due to rounding).

While both natural gas and coal prices have increased rapidly, natural gas is increasingly important in every region of the country. The slide shows that even in regions where coal has historically dominated – most noticeably in SERC– natural gas usage has grown substantially since 2000, up 63.6 TWh in 2007, more than in any other region. Noticeable increases also occurred in FRCC, which has flexibility to burn either gas or oil at many facilities, and also in the Rockies and Southwest where demand continues to grow considerably.

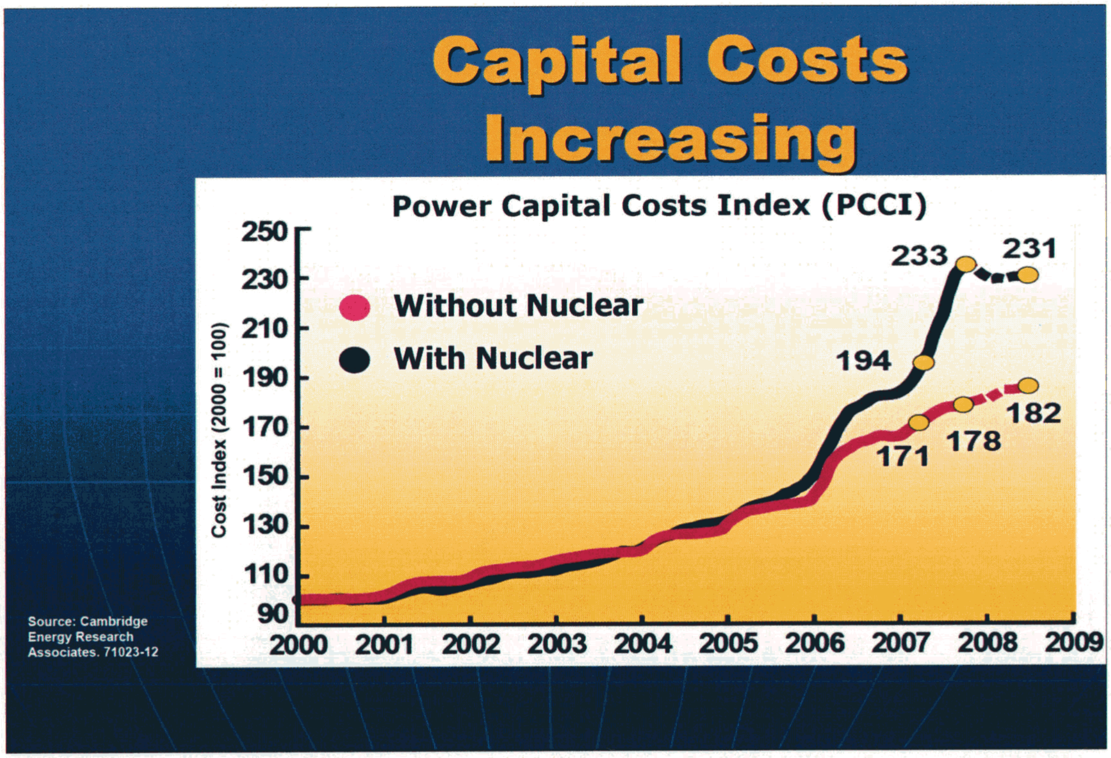
NERC Net Load Projections through 2016

Region	Total Difference (GW)	Percent Change
Northeast	9.7	17
RFC	23.2	13
SERC	28.2	14
FRCC	7.1	15
ERCOT	14.7	24
Midwest	17.2	21
WECC-Rockies and SW	7.6	25
WECC-CA and NW	10.9	10
Total	108.8	14

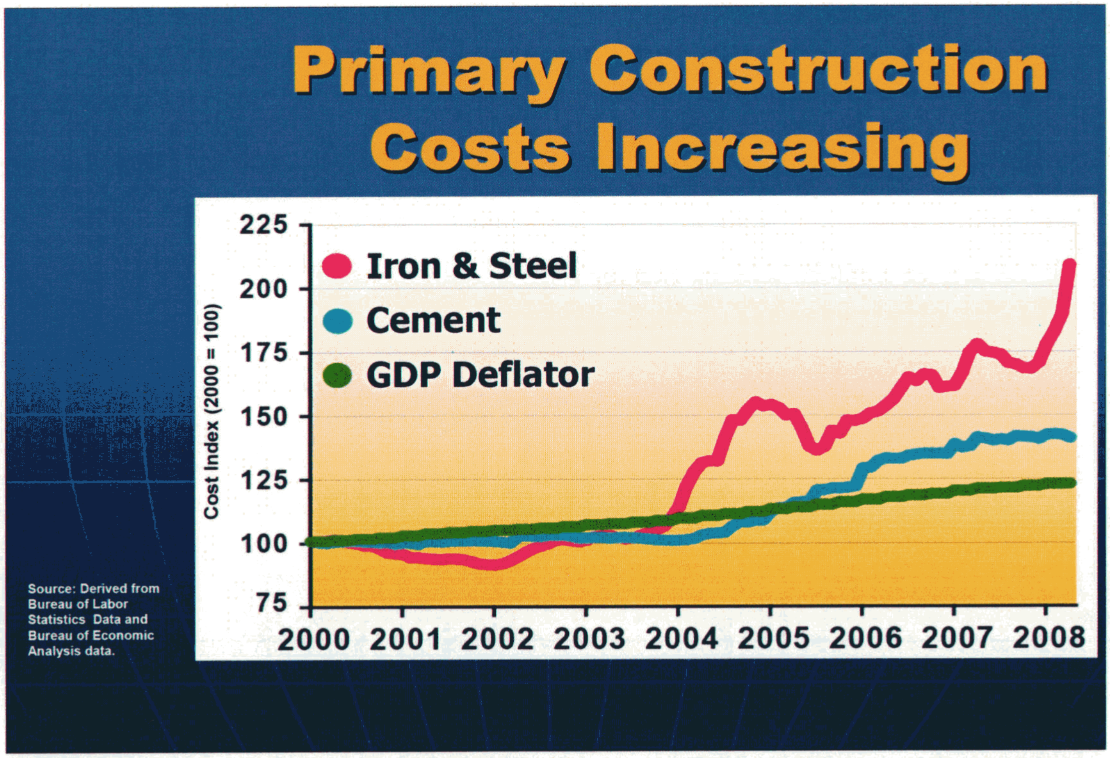
Source: Derived from NERC 2007 Long Term Reliability Assessment, Oct. 2007 and NERC data request, June 2008.

The second major factor that will put upward pressure on electric power prices is the increasing cost of new construction. This effect is particularly important because the country is entering a period when we will need to make substantial new investments, especially in generation.

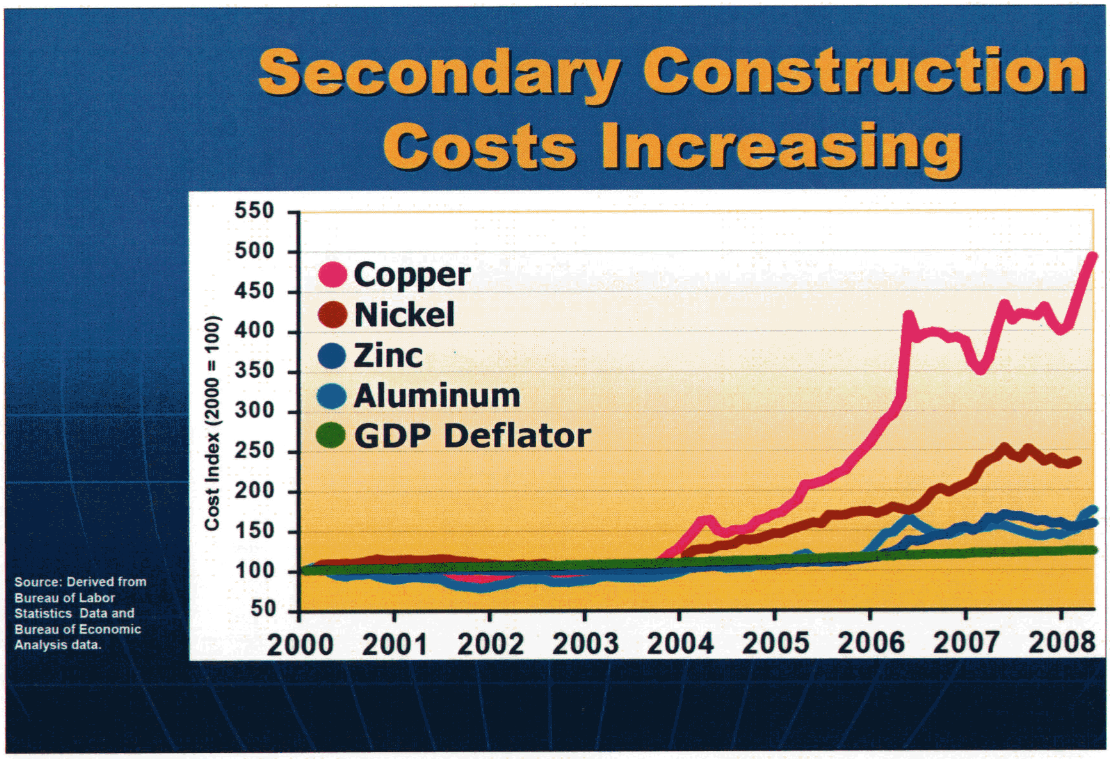
Natural gas fueled most of the last great wave of generation investment, which occurred between 1995 and 2004. In recent years, demand in most regions has gradually caught up with the capacity built around 2000. Looking forward, demand will continue to grow, and the need for new capacity will become ever more acute and ever more widespread. The slide shows NERC's expectation of peak net load growth in different regions for the next 10 years. We at the Commission are not in the business of forecasting, so I would just say this: There are legitimate reasons to be unsure about exactly how much new generation the country will need in the coming years. For one thing, higher prices will themselves discourage some power demand. Nonetheless, a significant level of demand increase seems virtually inevitable. So will be the need to build more capacity.



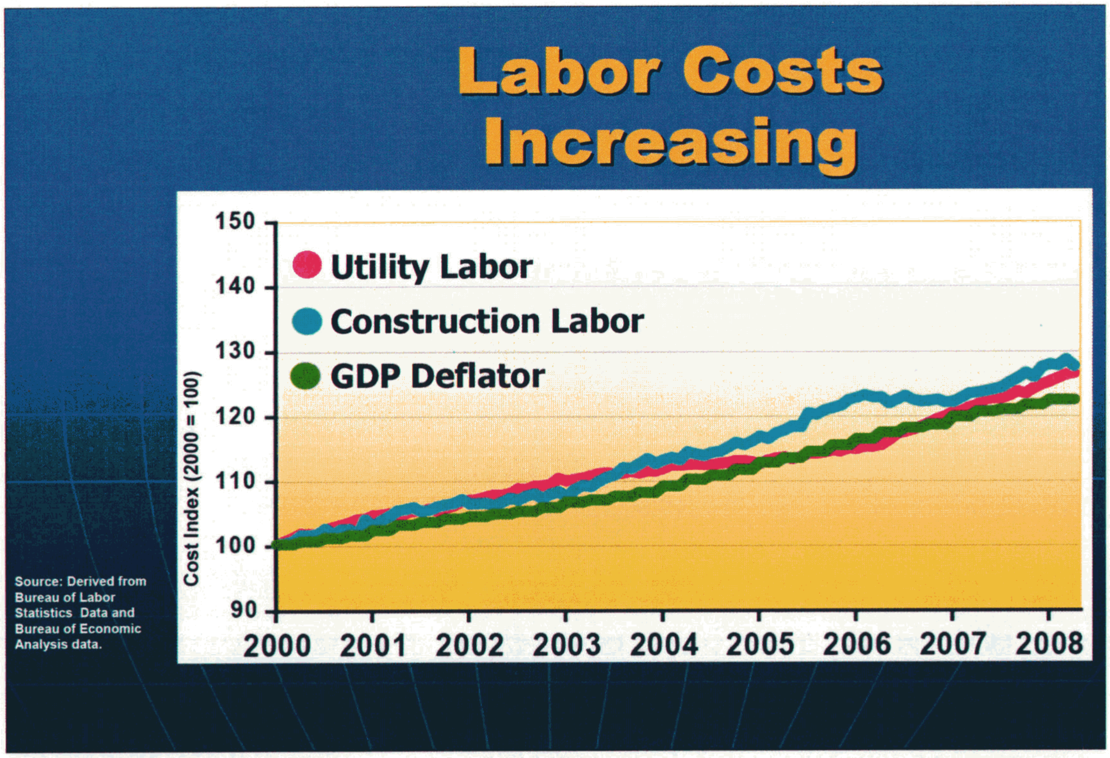
The need for new generation is important because new construction is becoming more expensive – quite aside from fuel price increases. Cambridge Energy Research Associates – CERA – produces an index of costs for the main inputs that go into building new generating plants. The slide shows how that index has almost doubled since 2003. The increase in nuclear plant inputs has risen even faster. Much of this cost increase results from rising global demand for basic materials. Part of it also comes from shortages of people to do key engineering and construction jobs. In any case, the implication is that, we will pay more, not less, for the next round of construction.



Let's look at some of the reasons that CERA's index is rising so rapidly. The slide shows two of the primary construction materials for electric generating plants – concrete is on the blue line and iron and steel on the red line. As you can see, the prices of both have been rising recently – especially steel, which is now more than twice as expensive as it was four years ago. Rising costs for iron and steel will also affect fuel prices for the power industry. For example, natural gas wells and pipelines both use substantial amounts of steel, so natural gas costs will also reflect rising iron and steel prices.

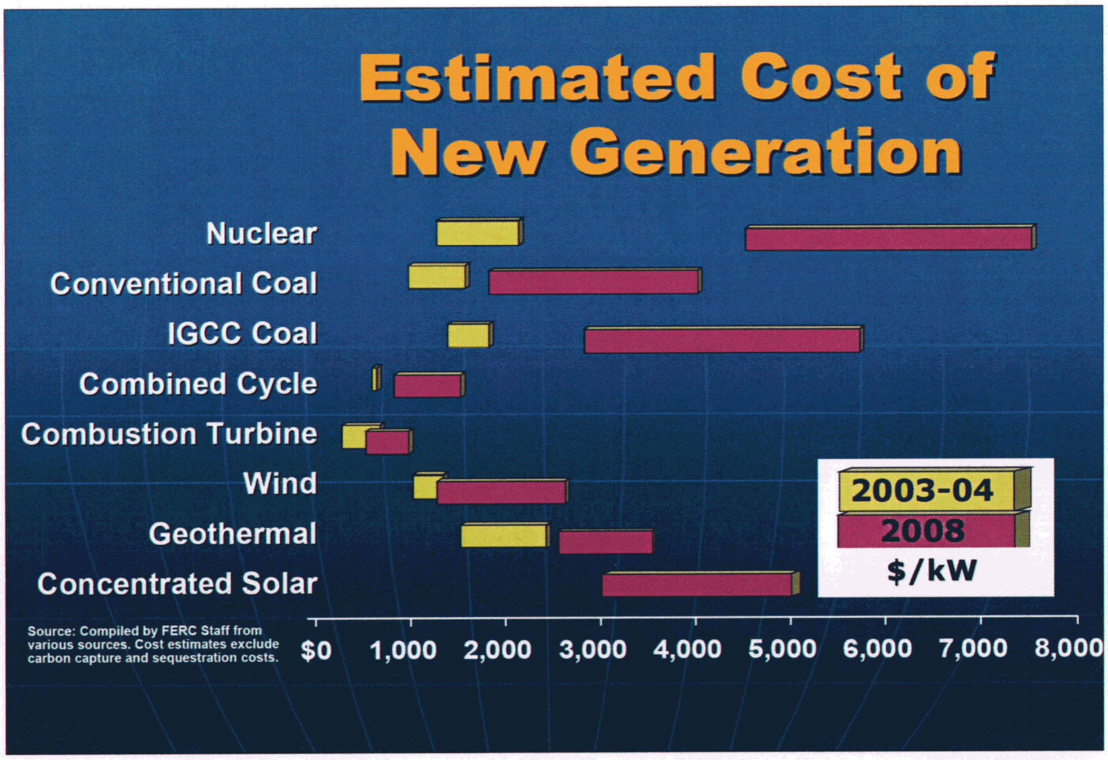


Of course, new generating plants require many other basic commodities. The slide shows the pricing for four key metals that go into generators. As you can see, all of these metals are increasing in price. The one that stands out is copper, up more than five times over the past four years. Indeed, copper is now so valuable there are reports of copper thieves cutting live cables to steal the metal.



Labor costs are also increasing. Perhaps the most frequently cited labor shortage is that for nuclear engineers. It has been a full generation since the nation built its last nuclear plant. Most of the engineers who worked on those plants are near retirement – and many have moved on to other occupations. In fact, the labor shortages are more widespread than just nuclear engineers. The slide shows that there has been about a 27% nominal change in average hourly earnings for both construction labor generally and for non-construction utility labor since 2000, outpacing inflation by over 4% for the same period.

In practice, the American labor market is quite responsive to market forces, so short-term labor shortages tend to be self-correcting over the mid-term. Still, there is no quick way to force several years of education into six months, or decades of experience into a year or two.



What do all these cost increases mean for the cost of building a new generating plant?

No one knows precisely. It's difficult to get consistent and trustworthy numbers about plant costs, both because they are commercially sensitive and because the assumptions behind them vary greatly. The numbers reflected on the slide come from a variety of sources and include different assumptions about, for example, location or exactly what facilities are included in the estimate. To take one example: Two recent nuclear procurements in South Carolina and Georgia produced cost estimates of $5,100 and $6,400 per kW, respectively, for the same technology. We have been told that most of the difference may be due to different uses of Allowances for Funds Used during Construction – AFUDC.

Despite the difficulties in being precise, the slide represents a good general indication of how capital costs have been changing. If anything, the cost estimates may be lower than the final costs of projects, if input costs continue to rise.

It's also important to remember that these cost estimates cover only capital costs. They do not include fuel costs, which as we've seen earlier will be a large factor for both natural gas and coal-fired plants. To the extent that plants do not have major fuel costs - they may be more competitive over their life cycles than would be suggested just looking at the capital costs. That would affect renewables and, to a degree, nuclear plants.

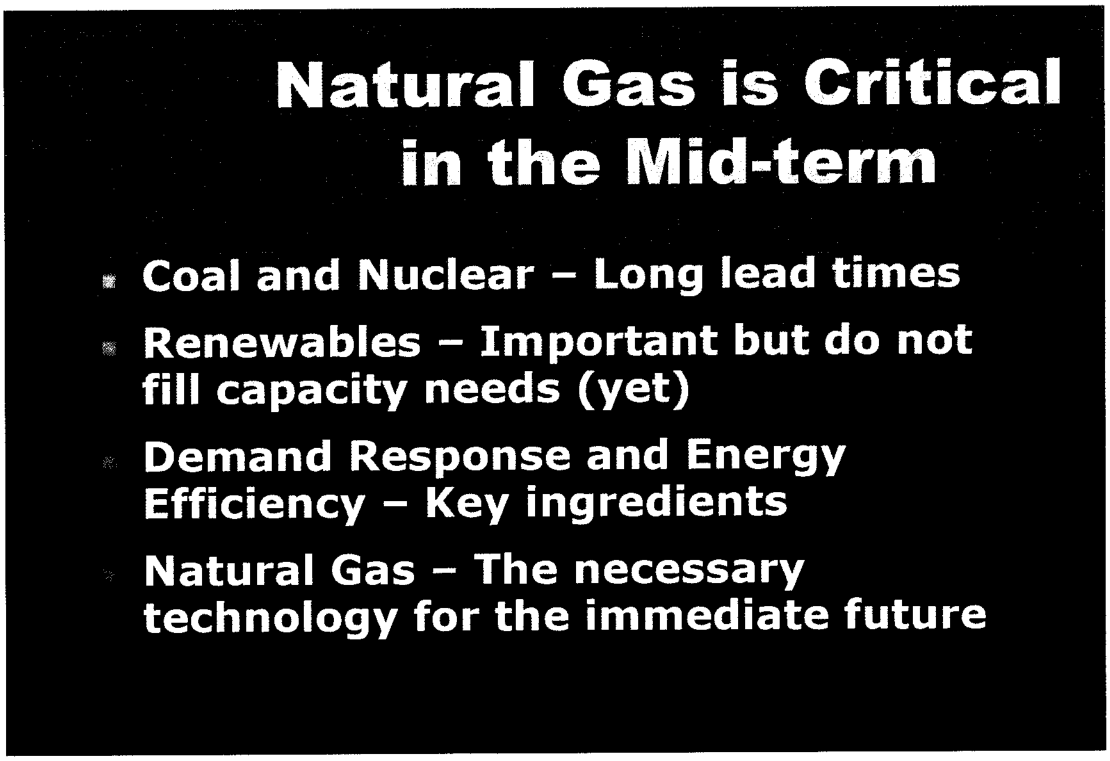
Similarly, these estimates generally do not include a full accounting of major risk factors, especially those affecting coal and nuclear plants. Both of these technologies have long lead times. That increases the chance that market conditions will change before they are complete and adds to the financial risk of building them. Nuclear plants also have risks associated with both decommissioning and waste fuel disposal. And coal plants have risks associated with the future treatment of greenhouse gases. Of course, relatively new technologies like wind and the new approaches to nuclear also have some risks, simply because they do not have the same track record of more mature technologies.

Climate Change Debate Affects the Market

- **Uncertainty about future carbon regime is a key factor**
- **Affects coal most of all**
  - Greater carbon emissions
  - Many plant cancellations
- **At the least, coal builds will be delayed**

Climate change has become an increasingly urgent national issue. The debate over how to address carbon dioxide emissions is lively and has already affected how companies think about investments. Until recently, rising natural gas prices made coal plants attractive. However, the national uncertainty about carbon policy has made investing in coal plants more risky. Without carbon capture or sequestration, coal unit emit about four times as much carbon as natural gas combined cycle units per MWh. Since January 2007, 50 coal plants have been canceled or postponed. Only 26 remain under construction.

Whatever the eventual result of the climate change debate, costs of producing power from both coal and natural gas are likely to increase. Moreover, as long as future climate change policy is unclear, market participants will have a considerable disincentive to invest in coal plants. Even when the issues are resolved, it remains an open question how competitive coal-fired generation will be, and it would take another four to eight years to build new coal-fired capacity.



Over the long run, the nation can meet its increasing need for generation in several ways. But for the next few years, the options are more limited, and natural gas will be crucial.

The lead times for both nuclear and coal units mean that they will not supply a significant amount of new capacity for nearly a decade.

Most people expect renewables to supply an increasing proportion of the nation's power. For the next few years, wind will almost certainly account for a large share of generation investment and will account for a growing share of overall generation. Wind power has no fuel costs, and so will generally operate when available. However, wind is a variable, weather-dependent resource. As a result, it will not make up as strong a share of the Nation's capacity needs over the next few years. Other renewables are becoming more competitive. Geothermal power is already an important resource in the west, and concentrated solar is becoming economically attractive in desert areas like the Southwest. But these sources are likely to remain relatively small in the national picture over the next few years.

Both demand response and energy efficiency will be important – I'll talk more about them on the next slide – but they are unlikely to eliminate the need for new capacity.

Overall, the most likely outcome is that natural gas will continue to be the leading fuel for new capacity over the next half decade. For example, the consulting firm, Wood Mackenzie estimates that in a carbon constrained environment, gas consumption for power will increase by 69 % by 2017. That's in addition to the 55% increase we've seen since 2000.

Over the years, we have learned repeatedly that people respond to prices. In the case of electric power, this is likely to take several forms.

First, there is likely to be more demand response. In the simplest terms, high prices at peak will lead some customers – both businesses and others – to prefer to save their money rather than use power. In fact, the first round of demand response may be both the cheapest and fastest way to improve capacity margins on many systems. The best cost estimates for the first rounds of demand response suggest that it should be available for about $165/kW, far less than any generation side options. The results of ISO-NE's first Forward Capacity Market auction last year corroborates the economic importance of demand response - 7.4 % of the accepted bids were for demand response. However, there are impediments that limit the full use of demand response. For example, most customers do not have the option to respond directly to real-time prices. As a result, they are unlikely to reduce peak consumption as much as they might prefer to if they could take advantage of the price.

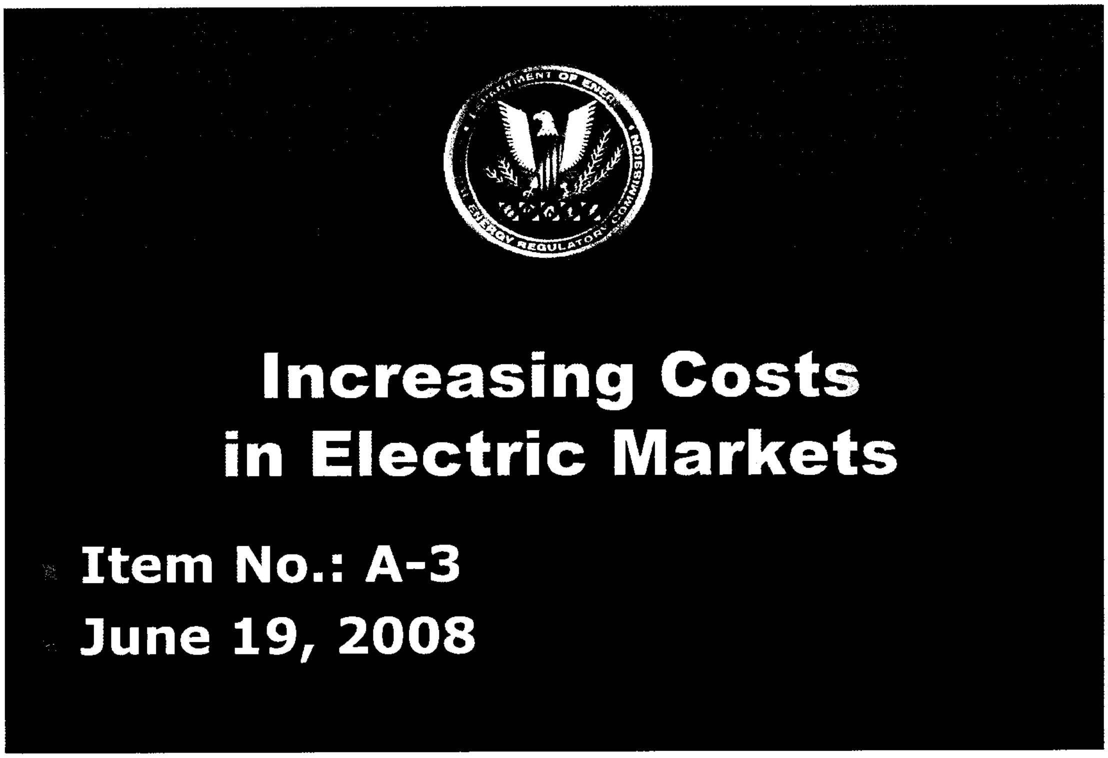
Second, customers are likely to be more energy efficient. While few customers see real-time prices, most get an average price over a month. As a result, high prices give them considerable incentive to reduce their overall consumption of power – though no more at peak than at other times. That is, energy efficiency is essentially a substitute for baseload capacity, while demand response is a substitute for peaking capacity. Energy efficiency is also likely to be economically important. Cost estimates show that the first round of energy efficiency may be available for about 3 cents/kWh. At

Continued on next page

Continued from previous page

current prices, supplying that same kWh from a combined cycle gas plant would cost 9 cents just for the fuel. Adding to the likelihood of greater energy efficiency is that many states have adopted fairly strong energy efficiency standards.

Third, innovators see higher prices as an opportunity. By the nature of things, it's hard to predict what innovations will succeed. The electric industry has a number of technologies that might take off – including concentrating solar power, hydrokinetic power, and vehicle to grid technologies. In addition, distributed generation is becoming more important, and may continue to do so for both cost and emissions reasons In other newly competitive industries, such as telecoms and natural gas, innovations have produced large changes, sometimes quickly. Given continuing high electric prices, the electric power industry may see similar results.



That concludes our presentation. We welcome comments and questions.

ARIZONA CORPORATION COMMISSION

September 5, 2008

Via E-mail Only

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Re: Staff's Responses to APS' Third Set of Data Requests in Arizona Public Service Company Motion for Approval of Interim Rate and Preliminary Order and General Rate Case; Docket No. E-01345A-08-0172

Dear Messrs Mumaw, Maledon, Metli and Ms. Grabel:

Enclosed are Staff's responses to Arizona Public Service Company's Third Set of Data Requests to the Arizona Corporation Commission Staff in the above-referenced matter.

Please do not hesitate to contact me if you have any questions regarding the attached.

Sincerely,

Amanda Ho
Attorney
Legal Division
(602) 542-3402

AH:klc

Enclosure

**ARIZONA PUBLIC SERVICE COMPANY'S
THIRD SET OF DATA REQUESTS TO
ARIZONA CORPORATION COMMISSION
Docket No. E-01345A-08-0172 – Interim Rate Motion
September 5, 2008**

Subject: To the extent available, requested information should be provided in searchable PDF, DOC or EXCEL files via email or electronic media.

APS 3.1 The table on Page 10 of the testimony of David Parcell dated August 29, 2008, lists as its source the AUS Utility Reports of July 2007 which are Exhibit 7 to his testimony. The information contained in Exhibit 7, however, does not appear to correspond to the numbers set forth in the table on Page 10 of the Parcell testimony. Accordingly, please provide the following:

1. The name of each of the companies in each "rating" category (i.e., Aaa/AAA through Not Rated) for both rating agencies listed in the table on Page 10 of the Parcell testimony.

2. With respect to the electric-only companies listed in Exhibit 7 to the Parcell testimony, do you agree that no company has an S&P bond rating as low as or lower than PNW?

3. With respect to combination electric and gas companies listed in Exhibit 7 to the Parcell testimony, please identify those companies that have an S&P bond rating as low as or lower than PNW.

RESPONSE: **The table on page 10 of Mr. Parcell's testimony cites as its source the July 2007 AUS Utility Reports. The numbers on the table on page 10 are in fact derived from the July 2007 AUS Utility Reports, as cited. The numbers shown on the table are correct for the period stated in the source.**

Attachment 7 to Mr. Parcell's testimony (not Exhibit 7 as stated in the Data Request) shows the August 2008 AUS Utility Reports. This is not the source of the table on Page 10. The table on Page 10 should have used the August 2008 AUS Utility Reports. A revised table, similar to that on Page 10 but reflecting the August 2008 AUS Utility Reports data, is shown on the following page.

Rating	Moody's	S&P
Aaa/AAA	1	
Aa1/AA+	1	
Aa2/AA	2	1
Aa3/AA-	2	2
A1/A+	4	1
A2/A	8	8

APS' FIRST SET OF DATA REQUESTS TO
ARIZONA CORPORATION COMMISSION
Docket No. E-01345A-08-0172
August _, 2008

Subject: To the extent available, requested information should be provided in searchable PDF, DOC or EXCEL files via email or electronic media.

A3/A-	12	16
Baal/BBB+	11	11
Baa2/BBB	**16**	13
Baa3/BBB-	3	**4**
Bal/BB+	1	1
Not Rated	4	5

As was the case in the table on Page 10 of Mr. Parcell's testimony, the bold numbers reflect APS' current ratings. The conclusions reached by Mr. Parcell on Page 10, lines 15-16, concerning this the information contained in this table remain the same when the August 2008 AUS Utility Reports data is substituted for the July 2007 AUS Utility Reports data. Thus, the updating of the bond ratings data does not impact Mr. Parcell's testimony and conclusions.

The responses to the specific questions posed in the data request are as follows:

1. **The information requested is contained in Attachment 7 to Mr. Parcell's testimony, which is the August 2008 AUS Utilities Reports.**

2. **No, Mr. Parcell does not agree with this. PWC has a S&P bond rating of BBB-Three other companies have a BBB- rating (NiSource, TECO Energy, and Westar) and one has a lower rating (BB+ PNM Resources). One of these (Westar) is listed by AUS Utility Reports as an electric-only company. It is noteworthy that 15 of the companies have a Moody's rating of Baa2 (i.e., APS and PWC rating) and three have a lower rating. Six of these are listed by AUS Utility Reports as electric-only companies.**

3. **Of the combination electric and gas companies, two have the same S&P rating as APS and PWC and one has a lower rating. These companies are identified in the response to 2 above.**

Press Release

Tue, Sep 02, 2008

Rocky Mountain Power announces changes in its Utah business

SALT LAKE CITY, Utah, Sept. 2, 2008 — Rocky Mountain Power must change the way it serves its Utah customers due to a recent rate decision issued by the Public Service Commission of Utah. Previously, the company had sought to balance three elements of utility operations: (1) service reliability to current customers; (2) ability to serve growing loads of new and current customers; and (3) low rates. After analyzing the commission's order, the company determined the commission did not provide sufficient revenue to support the electric service levels needed to meet Utah's growing demand for electricity. The commission has signaled by its order that the primary policy of the state is to keep rates low. To achieve this state policy objective and live within the budget set by the commission, Rocky Mountain Power will be making significant changes in the way it conducts business in Utah.

In its August order the commission granted Rocky Mountain Power a 2.7 percent tariff increase against a request for a 5.6 percent increase. The company's request for additional revenue reflected the cost to serve its Utah customers during calendar year 2008. It also reflected the cost associated with supporting the state's economic development and environmental goals while satisfying its regulatory commitments. The $38 million disallowed by the commission is required to respond to growth and to operate the company in the manner that Rocky Mountain Power previously believed customers expect and deserve. Consequently, today the company will be making a legal challenge to the commission's order by filing a petition for reconsideration of the commission's order requesting formal review of its decision regarding recovery of the company's power costs, property taxes, costs associated with generation overhauls, test year and return on equity.

"For more than a decade, Utah has enjoyed one of the fastest-growing economies in the United States," said Richard Walje, president of Rocky Mountain Power. "Growth does not come without significant challenges. The company has been investing billions of dollars to ensure sufficient generation, transmission and distribution capacity is available to meet this growth. The cost of providing for increased electric consumption by existing customers and the cost of providing service to new customers has exceeded the revenue the company receives from these customers. In response, we have aggressively managed our controllable costs through business efficiencies and energy efficiency programs designed to mitigate the impacts of growth and other cost reduction measures. However, these efforts have not fully offset the increased costs of serving existing and new electrical demand in Utah."

The cost of coal, natural gas and purchased electricity is increasing rapidly. As a result, the cost of electricity Rocky Mountain Power purchases and generates to serve customers in Utah is increasing sharply – up between $16 million and $20 million every six months. The costs incurred to purchase and generate electricity to serve the company's Utah customers during the first five months of 2008 exceeded the amount of revenue provided by the commission in its August order. That order currently creates a shortfall in net power cost recovery of $16 million in Utah for the company. The order also does not take into account the higher level of fuel and purchased power costs that will be incurred by the company to serve customers over the next year. This will increase the company's shortfall by an additional $27 million. In addition to increases in net power costs, the costs for critical commodities have had double- and triple-digit increases since 2001 – steel at 350 percent, copper at 349 percent and diesel fuel at 209 percent.

Unfortunately, the amount of revenue provided the company in the commission's order does not reflect the true cost of providing electrical service, and as a result the company is unable to continue its current approach to providing service.

Therefore, effective Sept. 15, 2008, Rocky Mountain Power will implement a hiring freeze directed at positions dedicated to serving customers in Utah. In addition, the company will:

·Further curtail the use of contractors;

·Limit overtime to the restoration of power only when employee or public safety is threatened;

·Seek relief and work with appropriate parties to reduce Utah property tax payments to the level allowed by the commission, as well as explore other options;

·Eliminate discretionary maintenance, discontinue funding of research associated with renewable and clean coal technology, and discontinue support for economic development activities;

·Review the level and types of corporate philanthropy; and

·Ultimately consider curtailing electric service when the cost of purchasing electricity to serve customers in Utah is prohibitive and exceeds the funding the commission provided to purchase and generate electricity to serve customers.

The company continues to investigate additional actions that can be taken to reduce costs, including changes in the operations of the company's customer contact centers, while remaining in compliance with all local, state and federal regulations.

While these actions are necessary given the recent commission order, the primary driver of price increases – growth in the demand for electricity – must be addressed if the policy to maintain low prices inherent in the commission's order is to be achieved. Consequently, Rocky Mountain Power will aggressively work with elected officials and the commission to reduce the growth in Utah's demand for electricity.

Requests will be submitted to the Public Service Commission of Utah and, if necessary, to elected officials to mandate customer participation in electricity demand-management programs, to eliminate line extension allowances for new customers, to institute marginal pricing for large industrial customers and to send appropriate pricing signals to customers through the use of an energy cost adjustment mechanism similar to the commission-allowed adjustment Questar uses in establishing natural gas prices.

The company is evaluating the impact these changes will have on the projected growth in the demand for electricity, and will recommend other policy changes, if necessary, to ensure the delivery of safe, adequate service to customers in Utah.

Unfortunately, these actions are necessary to bring the cost of providing service in Utah in line with the revenue the company will receive based on the commission's recent decision.

"The employees and management of Rocky Mountain Power are committed to serving our Utah customers to the best of our ability and we regret the impact the recent decision of the commission will have on the level of service we are able to provide," Walje said.

Media inquiries: 800-775-7950; newsdesk@pacificorp.com

Increased Revenue Requirements on the Growth in the ACC Jurisdictional Rate Base Since APS' Last Rate Case ($m)

Line	Period	Plant Additions (1)	Less: Rate Base Deductions (2)	Net Rate Base Additions (3)	Revenue Requirement On Net Rate Base Additions (4)	Revenue Requirement On Increased Book Depreciation (5)	Total Incremental Revenue Requirement (6)	Annual Revenue Requirement Deficiency (7)
1	9/30/05 to 12/31/07	$1,114	($576)	$538	$65	$30	$95	($95)
2	2008	$838	($437)	$401	$49	$23	$72	($167) **
3	2009	$907	($444)	$463	$56	$24	$80	($247)

Notes:

** Annual revenue requirement deficiency on ACC rate base growth through June 30, 2008 equals ($139.9) million (see Mr. Rumolo's exhibit DJR_RB-1)

(1) $1,114 is the change in gross utility plant on schedule B-1 from the last ACC decision to the current case. 2008 and 2009 figures are from attachment DAK-2.

(2) Includes changes in accumulated book depreciation, deferred income taxes, and other rate base items.

(3) $538 is from attachment RCS-4. 2008 and 2009 figures are from attachment DAK-2.

(4) Equals net rate base additions x 8.32% cost of capital from the last ACC decision, adjusted for interest synchronization and the revenue conversion factor.

(5) Equals plant additions x an effective 2.7% book depreciation rate.

(6) Excludes incremental revenue requirements from additional property taxes.

(7) Equals the annual revenue requirement increase since the last test year, for rate base additions through that period.

Integrated Utility Equity Deals Since 2004

Pricing Date	Issuer	Deal Size ($mm)	Deal Size % Mkt Value	File to Offer	Offer to Current
05/29/08	Westar Energy Inc	146	6.1%	3.3%	(6.7%)
12/06/07	Empire District Electric Co	69	9.6%	(0.2%)	(8.3%)
12/05/07	Sierra Pacific Resources	204	4.9%	(4.2%)	(33.9%)
11/15/07	Westar Energy Inc	207	8.2%	(2.2%)	(10.3%)
11/08/07	Pepco Holdings Inc	176	3.5%	(3.9%)	(6.1%)
06/12/07	Portland General Electric Co	615	36.9%	(11.8%)	(1.5%)
05/11/07	Consolidated Edison Inc	559	4.1%	(0.3%)	(19.5%)
03/21/07	Energy East Corp	243	6.6%	0.4%	12.2%
12/12/06	Avista Corp	69	5.4%	(4.1%)	(11.0%)
12/06/06	PNM Resources	177	7.6%	(1.5%)	(61.7%)
09/21/06	ConEdison	447	3.8%	(0.6%)	(18.3%)
08/14/06	Cleco Corp	164	11.9%	(2.8%)	6.1%
08/10/06	Sierra Pacific Resources	282	8.8%	(2.8%)	(20.3%)
06/15/06	Empire District Electric Co	77	12.6%	(7.2%)	4.2%
05/17/06	Great Plains Energy Inc	193	8.6%	(3.0%)	82.3%
12/06/05	Northeast Utilities	439	15.3%	1.1%	40.9%
11/15/05	WPS Resources	247	12.2%	(4.7%)	(32.0%)
10/27/05	Puget Energy	312	13.0%	(2.4%)	34.1%
04/27/05	Pinnacle West Capital	256	6.3%	(1.4%)	(16.2%)
03/30/05	CMS Energy Corp	282	11.8%	(3.6%)	10.8%
03/23/05	PNM Resources	105	6.1%	(4.3%)	(55.9%)
12/09/04	Idacorp Inc	121	9.6%	(4.9%)	(0.7%)
12/07/04	Otter Tail Corp	78	10.6%	(5.3%)	56.0%
10/07/04	CMS Energy Corp	298	19.6%	(2.7%)	49.1%
09/09/04	Pepco Holdings Inc	288	7.9%	(5.4%)	31.7%
09/07/04	Dominion Resources	652	2.9%	(0.4%)	(33.2%)
08/18/04	Aquila Inc	117	19.5%	(17.2%)	NA
06/30/04	Ameren Corp	459	5.9%	(2.2%)	(0.3%)
06/28/04	Constellation Energy Group Inc	228	3.6%	(1.6%)	75.8%
06/08/04	Great Plains Energy Inc	150	6.7%	0.3%	(21.8%)
05/11/04	Consolidated Edison Inc	528	5.8%	(3.2%)	8.4%
03/25/04	Westar Energy Inc	249	14.4%	3.8%	9.7%
03/10/04	Hawaiian Electric Industries Inc	104	5.0%	(2.0%)	(49.0%)
02/03/04	Ameren Corp	875	11.3%	(3.5%)	(8.8%)
	Total/Average (34):	**9,414**	**9.6%**	**(3.0%)**	**0.2%**

Source: Dealogic as of August 29, 2008. Includes utility and power equity & equity-linked offerings greater than $50 million in proceeds.

LEHMAN BROTHERS
EQUITY RESEARCH

September 02, 2008

United States of America
Power and Utilities
Regulated Utilities
Daniel Ford, CFA
1.212.526.0836
daford@lehman.com
LBI, New York

Pinnacle West Capital (PNW - US$ 35.19) 2-Equal weight

Company Update

Staff Testimony in Interim Rate Request

Investment Conclusion

- We reiterate our 2-EW rating, our $33 price target and our earnings estimates of $2.47/$2.48E in 2008 and 2009 respectively.

Summary

- ACC Staff has filed testimony in PNW's request for interim rate relief which would put in place an interim base rate surcharge of $.003987/kWh to become effective upon the expiration of the $.003987/kWh 2007 PSA charge. This would equate to ~$115M in annual revenues and be subject to refund pending the full outcome of the current rate case filed at the ACC under docket E-01345A-08-0172.
- Staff recommended that an emergency or the conditions otherwise warranting an interim increase have not been met, however, if the ACC does grant an increase it should be ~$62M, and require the infusion of ~$400M of equity into the utility before becoming effective. The AECC, an industrial intervenor recommended an increase of ~$42M. RUCO requested an extension of testimony until today.
- We view the $400M equity infusion as difficult to meet given the current environment for equities, and specifically given that PNW's equity is currently trading below book value.

EPS (US$) (FY Dec)

	2007	2008			2009			% Change	
	Actual	Old	New	St. Est.	Old	New	St. Est.	2008	2009
1Q	0.17A	-0.04A	-0.04A	-0.04A	N/A	N/A	0.07E	-124%	N/A
2Q	0.79A	0.93A	0.93A	1.03A	N/A	N/A	0.75E	18%	N/A
3Q	1.98A	N/A	N/A	1.62E	N/A	N/A	1.66E	N/A	N/A
4Q	0.03A	N/A	N/A	-0.07E	N/A	N/A	0.00E	N/A	N/A
Year	2.96A	2.47E	2.47E	2.46E	2.48E	2.48E	2.54E	-17%	%
P/E			14.2			14.2			

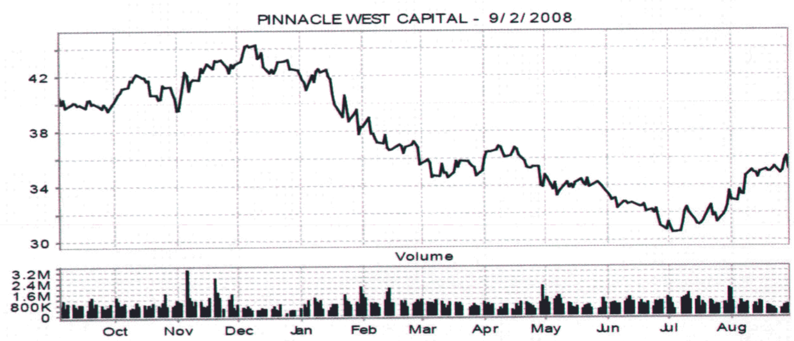
Market Data

Market Cap (Mil.)	3545
Dividend Yield	5.97
52 Week Range	44.50 - 30.26

Financial Summary

Revenue TTM (Mil.)	3628.0

Stock Overview



Source: LehmanLive

Stock Rating

New: 2-Equal weight
Old: 2-Equal weight

Target Price

New: US$ 33.00
Old: US$ 33.00

Sector View: 2-Neutral

Analyst Certification:

I, Daniel Ford, CFA, hereby certify (1) that the views expressed in this research Company Note accurately reflect my personal views about any or all of the subject securities or issuers referred to in this Company Note and (2) no part of my compensation was, is or will be directly or indirectly related to the specific recommendations or views expressed in this Company Note.

PLEASE SEE ANALYST(S) CERTIFICATION(S) ON PAGE 1 AND IMPORTANT DISCLOSURES BEGINNING ON PAGE 3

RAW MATERIAL PRICE INCREASES

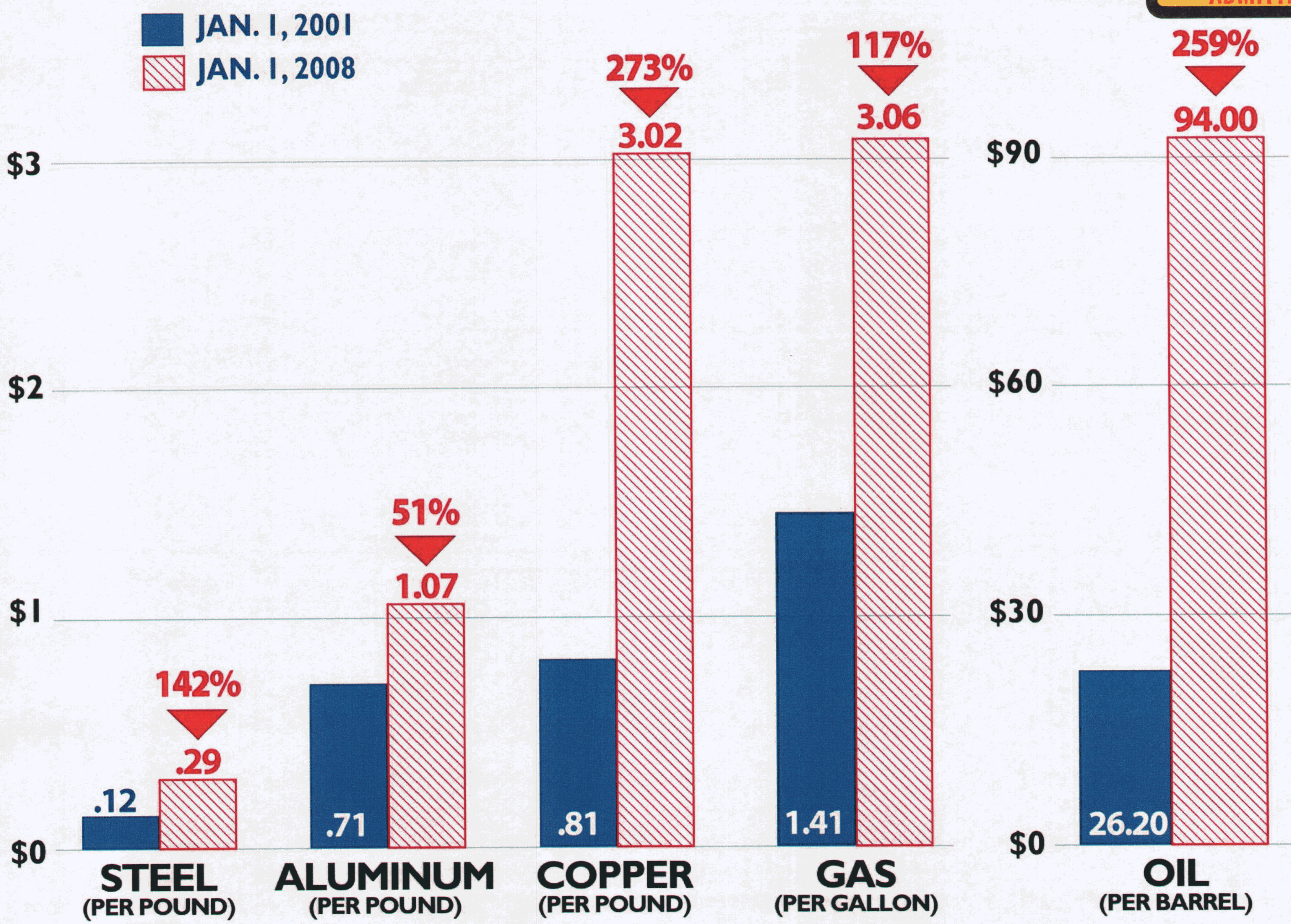


EXHIBIT
AP5-4
ADMITTED

PER CUSTOMER DISTRIBUTION PLANT INVESTMENT RISES WITH INFLATION

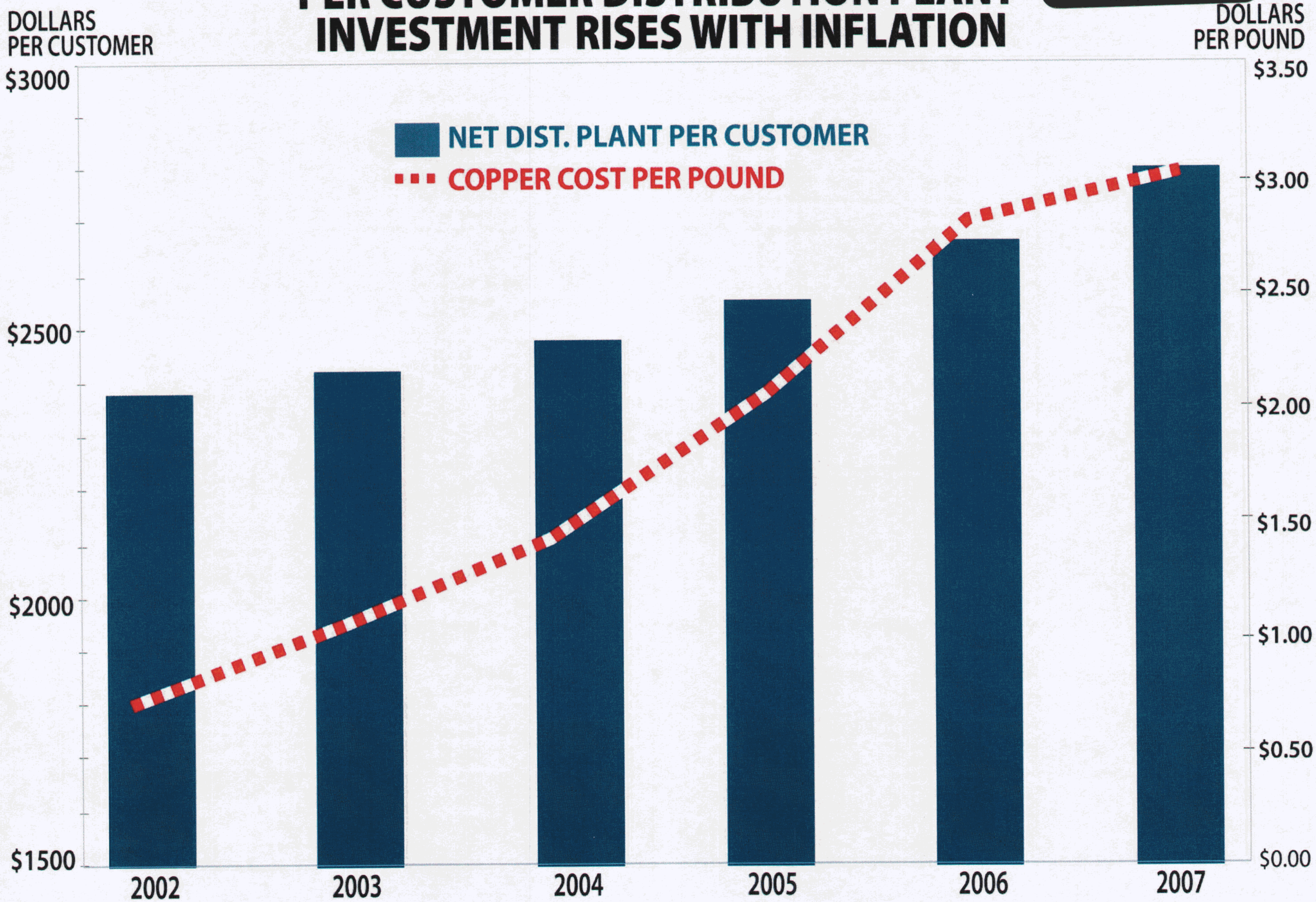
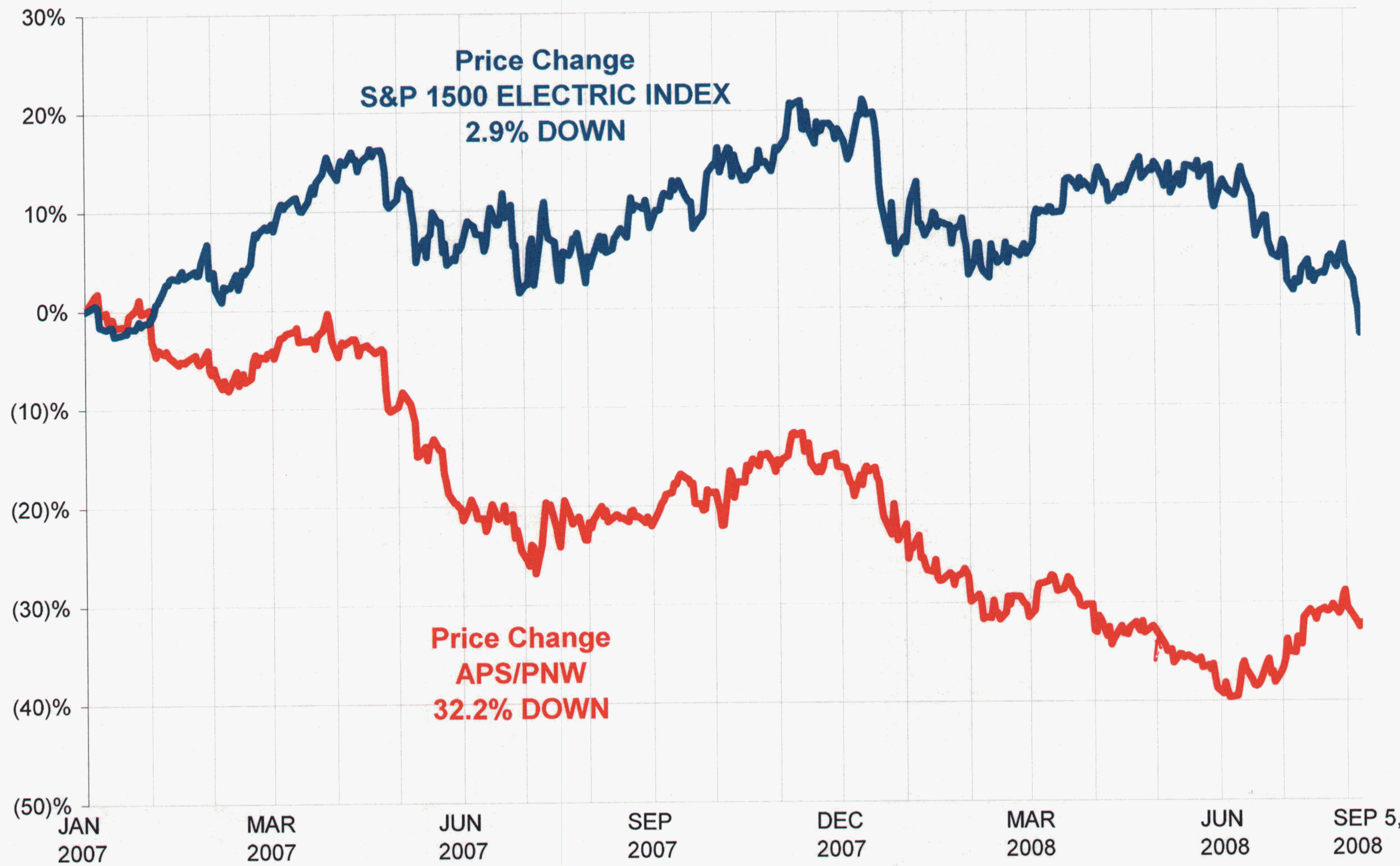
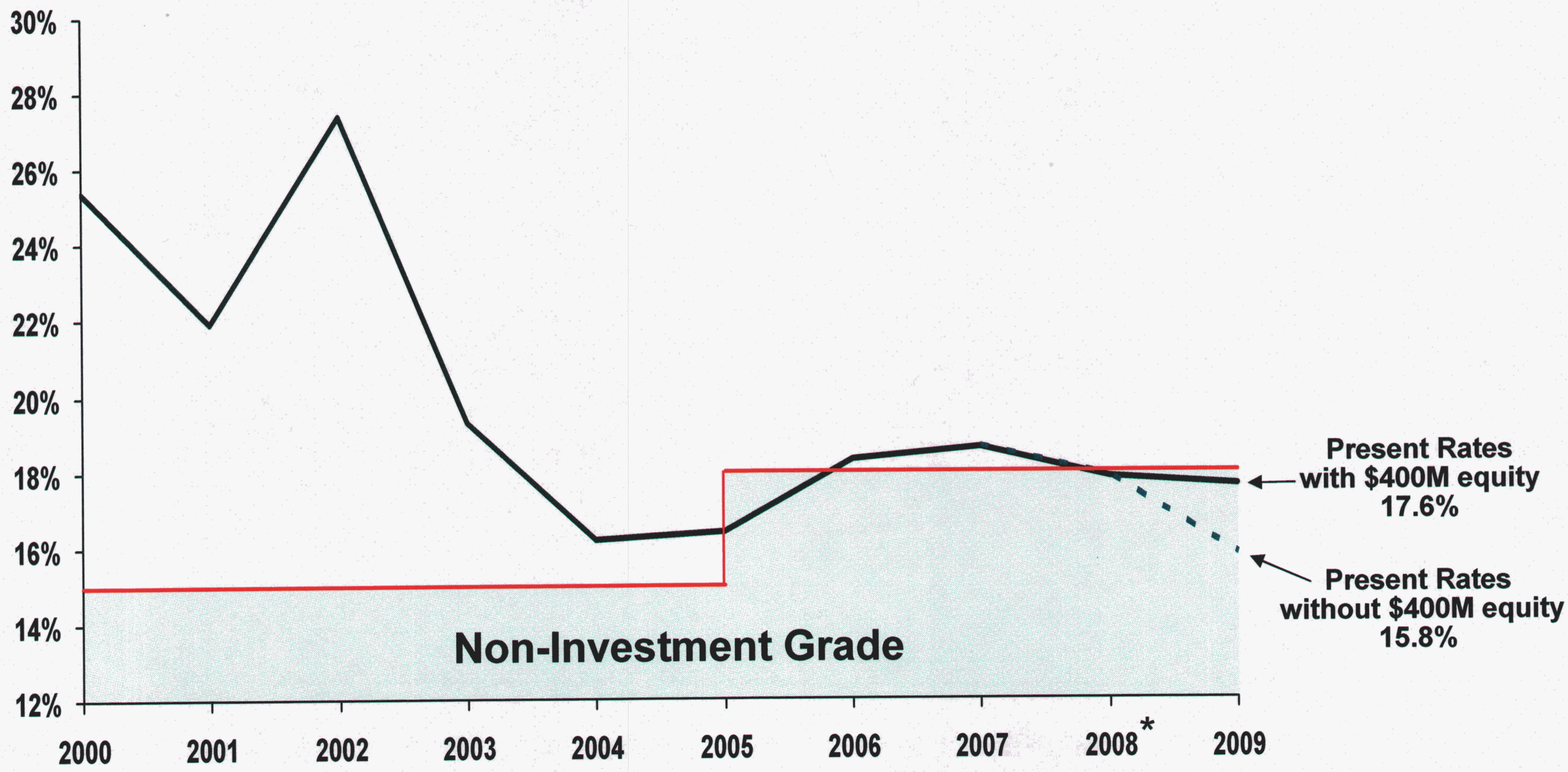


EXHIBIT
APS-5
ADMITTED

STOCK PRICE COMPARISON
JANUARY 1, 2007 - SEPTEMBER 5, 2008



Arizona Public Service Company
FFO/Debt



* 2008 is adjusted to exclude one-time cash flow benefits from bonus tax depreciation and special PSA surcharge

Capital Expenditure Reductions
Cost Review

More than $200 Million over next five years

$ 130 Million	Slower projected customer growth
$ 60 Million	Improved planning, logistics and scheduling
$ 20 Million	Deferral of system upgrades and projects not affecting reliability *

* Construction project deferrals ($ in Millions)

Coolidge - Southeast Division Future Substation 69kV line	2
Goodyear Future Substation - Rainbow Valley 69kV line	1
Estrellita - Goodyear Future Substation 69kV line	2
Goodyear Future Substation - Goodyear Future Substaton 69kV line	2
Prince Mountain - Future Substation 69kV line	1
Prince Mtn - Calderwood 69kV line	2
Raceway - Twin Buttes 69kV line	2
Ashfork - Williams 69kV line	3
Tonto - Childs 69kV line	2
Other / rounding	3
Total	20

Potential Range of APS Construction Expenditure Changes
(Lower) / Higher than Exhibit DEB-3 (General Rate Case Forecast)
$ Millions

	2009	2010	2011	2009 to 2011 Total
Production	(60) to (70)	(55) to (65)	40 to 30	(75) to (105)
Transmission	(60) to (70)	(185) to (195)	(165) to (175)	(410) to (440)
Distribution	(10) to (20)	(35) to (45)	(115) to (125)	(160) to (190)
General Plant	(65) to (75)	(35) to (45)	95 to 85	(5) to (35)
Total excluding Schedule 3 CIAC	**(195) to (235)**	**(310) to (350)**	**(145) to (185)**	**(650) to (770)**
Schedule 3 CIAC Change	35 to 25	55 to 45	120 to 110	210 to 180
Total Potential Change Range	**(160) to (210)**	**(255) to (305)**	**(25) to (75)**	**(440) to (590)**

EXHIBIT
APS-9
~~ADMITTED~~

APS' 12/31/2009 Projected FFO to Debt Ratio
Higgins Interim Proposal Adjusted to Remove Equity Issuance ($m)

	12/31/2009				
	Higgins $42.4m Interim Proposal With $400m Equity (KCH-2, p.2)	Impacts of Removing Equity	Higgins $42.4m Interim Proposal Without $400m Equity	Add $124m of Additional Revenues Needed to Hit 18.25% FFO to Debt \2	Result With $166m (42.4+124) Interim
FFO	807	(15) \1	792	74.4	866
Adjusted debt	4,422	400	4,822	(74.4)	4,748
FFO to debt	18.25%		16.4%		18.25%
Interim Increase	$42.4M			$124M	$166.4M

\1 400m more debt x 6.25% = 25m higher interest x 60% = $15 after tax = $15m lower ffo for 2009

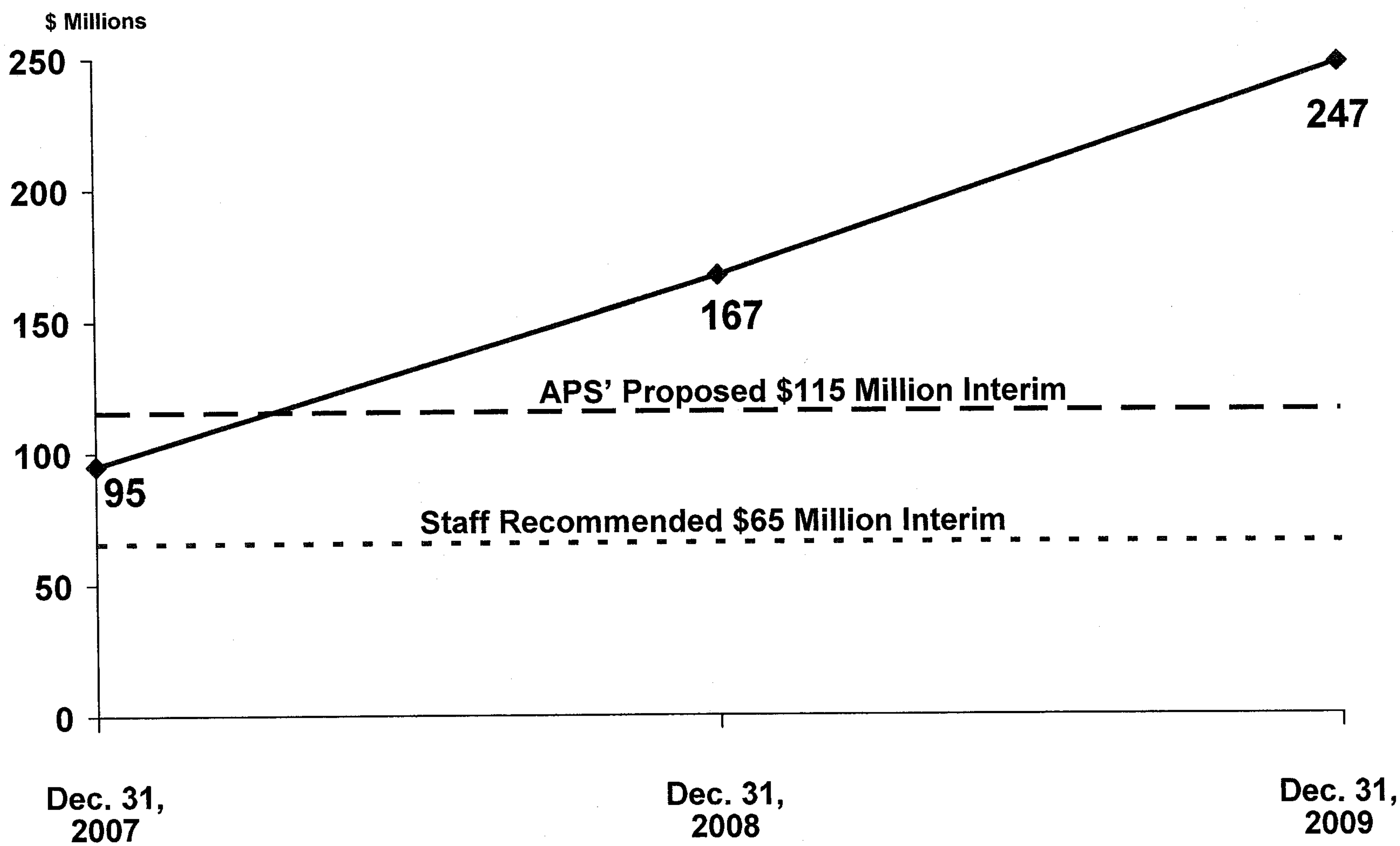
\2 $124m additional revenues x 60% = 74.4m after tax

Conclusion: Without an Equity Issuance, APS would require an Interim increase of $166.4M in order to achieve an FFO to Debt Ratio of 18.25%.

EXHIBIT APS-10 ADMITTED

Annual Revenue Requirements for Return On and Return Of Growth in ACC Rate Base Since September 30, 2005 Test Year*

$ Millions



*From June 2007 Decision 69663

EXHIBIT
APS-11
ADMITTED

REBUTTAL TESTIMONY OF WILLIAM J. POST

On Behalf of Arizona Public Service Company

Docket No. E-01345A-08-0172

(Interim Rate Request)

September 8, 2008

TABLE OF CONTENTS

REBUTTAL TESTIMONY OF WILLIAM F. POST
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-08-0172)
(Interim Rate Request)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is William J. Post. My business address is 400 N. 5th Street, Phoenix, Arizona, 85004.

Q. WHAT IS YOUR POSITION WITH ARIZONA PUBLIC SERVICE COMPANY ("APS" OR "COMPANY")?

A. I am Chairman of the Board for APS. I am also Chairman and CEO of Pinnacle West Capital Corporation ("Pinnacle West").

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS MATTER?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. I will explain why it is critical both for the Company and for our customers that APS receive interim rate relief in this proceeding. In that regard, I take strong exception to the conclusions of Staff consultants Ralph Smith and David Parcell, as well as those of Stephen Ahearn of the Residential Utility Consumer Office ("RUCO").

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. What the Commission must decide in this case is not just the definition or application of a word ("emergency"). Neither must it find that APS rests perilously on the edge of an immediate financial disaster in order to conclude that interim rate relief is in the public interest. Rather, this proceeding provides the opportunity to continue to move APS and our combined public-private decision model with the Arizona Corporation Commission ("Commission") to the level required to meet the state's energy future. Effective decisions concerning energy policy are made today across the country through the cooperative efforts of state regulatory agencies and utilities. Evidence the activities of Florida, North Carolina, Georgia and California to establish energy policy and create the necessary structure to achieve the associated energy policy goals.

In this regard, the Commission has made significant progress with APS to modify and in some cases establish new methods toward the establishment of such a public-private decision model. The re-regulation of APS as a vertically integrated utility, the approval and implementation of a comprehensive power supply adjustment clause as well as a mechanism for a more timely recovery of transmission costs, the development of a new resource planning structure, the approval of a renewable resource portfolio standard and a deepened commitment to DSM, and most recently adoption of a new line extension process, have all been developed over the last 3 years. Collectively, these changes have modified the historic regulatory structure to develop a more contemporary decision model that incorporates the realities of today's energy challenges.

Two important steps remain. First, the creation of a structure to reduce the substantial regulatory lag in Arizona and second, the method to approve and acquire new base load energy resources. This hearing deals directly with the first step and will be dispositive of Arizona's options for the second step.

APS requested interim rate relief to reverse the clear and undeniable decline in the Company's financial strength – a decline that threatens the Commission and APS's ability to usher in the sustainable energy future that is within our grasp. I hope and believe that the Commission will share our goals and will take this opportunity to send a message to the utility industry, rating agencies and the financial markets that this Commission understands the need of a financially stronger APS to provide for future customers in a timely and fiscally responsible manner.

APS CEO Donald Brandt has presented the financial arguments for interim relief, describing both the source of and the solution to the Company's ongoing financial decline. He has also described the potential disaster to APS customers that would accompany the failure to arrest that decline through the grant of interim rate relief. I will not repeat his arguments. Instead, I describe why I believe it is critical for this Commission to grant interim relief and, by doing so, to continue to build on the track record of steady improvements to this state's regulatory model that have been implemented over the past three years.

III. WHY APS NEEDS INTERIM RATE RELIEF

Q. WHY DOES APS NEED INTERIM RELIEF AND WHY DOES IT NEED IT NOW?

A. A positive interim rate decision is vital for six reasons. Each one individually provides a stand-alone basis for approval of this request; collectively they show the positive opportunity we have to move our State forward with a leading regulatory structure, one that will allow Arizona to continue to determine its own energy future.

A. Regulatory Lag

Regulatory lag should never be accepted as "normal." And in any form, it is not beneficial to our customers, our investors, or our State. Moreover, there is nothing "normal" about setting rates today based on a rate base and cost of service that in many instances are as much as three years old unless one were to assume that rate base and cost of service had remained unchanged over time. Although I realize our State has a strong constitutional foundation to pricing electric and other regulated services, it also provides this Commission the authority to modify the process to meet changing conditions.

For example, in 1999, after several years of discussions, hearings and legislative and regulatory decisions, our State decided de-regulation of generation and other services was an appropriate goal and established a process to completely disassemble an 87-year history of vertical integration and regulation of electric utilities. Although this Commission subsequently reversed most aspects of de-regulation and has placed other aspects of retail electric competition on hold pending further study, this and other experiences show that it is possible to modify and improve the regulatory model in our state.

Don Brandt describes the negative financial impacts of regulatory lag. I would add that regulatory lag also fails to provide the appropriate price signal to our customers, which affects both short and long-term decisions concerning energy consumption and resources. This is particularly harmful to customers when APS, with this Commission's strong support, is making and will continue to make such a substantial commitment to energy efficiency and conservation programs. Incorrect or even delayed price signals only serve to frustrate these goals. The regulatory lag experienced by APS also inherently reinforces the inaccurate impression that APS is only interested in increasing prices and that the Commission is only concerned with delaying price increases. This appearance of an over-emphasis on process versus a full factual and policy examination of all rationales for a given price level leads outsiders to incorrect conclusions about the intent of the Commission. Processes are important, and they provide this Commission with a sound basis for decision-making; however, they should never substitute for nor limit the Commission's authority to apply its own sound judgment to changing conditions.

B. Consistent Objective and Goals

Analyst reports and rating agency releases have incorrectly and unfairly left some with the impression that this Commission is anti-APS or hostile to investment. I have never believed this picture was an accurate portrayal of what was going on in Arizona, particularly with respect to APS. I am confident that the objectives of our Company and those of the Commission are fundamentally consistent with each other. One of the important and fundamental process tools for decision-making is the fact-finding hearing process. Unfortunately, the sometimes-adversarial nature of this process leads some to believe we have divergent objectives for customer growth, customer service, reliability, fuel diversity, financial strength and economic development for our state. By granting interim rate relief in this case, we have the extraordinary opportunity not only to improve the capital market's understanding of our unity of purpose in attracting capital for new infrastructure at the lowest possible cost but to impress on the market, and indeed the entire industry, our combined commitment to a healthy APS and sustainable energy future for our state.

Even more than in the past, the combined efforts of our Company and the Commission are needed to efficiently maintain future energy independence for our state. In the past, the Commission has assumed leadership roles in helping to expand Arizona's coal-fired generation and add nuclear power to the mix during the late 1970s and 1980s by providing consistent regulatory support in the form of CWIP, attrition allowances, regulatory accounting orders and also interim rates. In the 1990s, this Commission adopted a unit cost pricing model that reinforced the important aspects of cost efficiency and productivity. Later, the Commission halted the move toward restructuring in time to prevent a California-like debacle in Arizona, with APS acquiring the critically needed new generation that had been built by Pinnacle West Energy. And more recently, this Commission has approved and implemented effective rate adjustment mechanisms for fuel and purchased power and critically needed transmission infrastructure. It then moved to address escalating costs of distribution by approving a new and innovative approach to new or expanding electric service extensions via the changes to APS Service Schedule 3.

This is a significant record of accomplishment, and one that I believe is not fully appreciated by those who influence the capital markets due in part to an overemphasis on the contentious discussions in our sometimes adversarial hearing process. Now, it is time for both of us to step up and take leadership in establishing a comprehensive vision for Arizona's future. That vision should include significant additional investments in new infrastructure, new technology, energy efficiency, and new more sustainable resources. It should also be focused on maintaining energy independence for APS and Arizona. The tools required include a financially strong APS rather than a utility that continuously bumps along the bottom of the investment grade world suffering from chronic and severe earnings shortfalls. We have established an internal goal of achieving 100% internal cash generation of our capital requirements by 2011, however this goal will be unachievable by 2011 or any other date without Commission support for the recovery of our costs.

If it seems like I sound like a broken record on the theme of new investment, that is entirely intentional. We cannot hope to achieve any of our mutual goals without the need for new investment in Arizona infrastructure. In addition, that new investment will not be possible unless APS regains a solid investment grade rating (BBB or higher), can earn its cost of equity capital on a regular basis and can approach and eventually reach energy and financial self-sufficiency. We will never be successful if we settle for a financial goal that keeps APS on the perilous edge of downgrade and mired in massive deficit financing as Mr. Brandt describes in his Affidavit on pages 7-9.

C. Financial Strength

APS and indeed our state needs to have the ability to pursue all available generating resource options. This requires both the time to implement as well as the ability to finance the right alternative. Although today we do not see the need for new base load generation until later into the next decade, the lead-time for completion of these projects makes the decision for them timely. The time to evaluate and consider future resource options is now even if new base load generation will not be needed to serve load for several years. APS will not be able to realistically consider capital-intensive resource options (whether built by APS or by others and contracted to APS) such as nuclear, large-scale solar projects such as Solana, or even new clean coal technology with a marginally investment-grade status that is under constant pressure from growth and cost increases combined with excessive regulatory lag. This very real possibility that APS and this Commission will be prevented from considering what may be superior energy options for Arizona is an energy crisis no less real than those that faced Arizona in the 1970s and 80s, and most recently in the early years of this decade.

When APS was last granted non-fuel interim base rate relief, it was 1984 and the concern then expressed by the Commission was that APS might fall from BBB+ to BBB, which in turn would jeopardize its ability to finance Palo Verde. How far have we fallen to now set our sights, as have Staff's consultants and the Intervenor witnesses, on the bottom reaches of BBB-, when the challenges facing APS, its customers, and this state are at least as great as those faced in the 1970s and 80s?

In 1999, after five years of workshops, hearings, legislative efforts and regulatory decisions, the Commission finally approved an electric restructuring plan for APS in the form of a 1999 Settlement Agreement. That plan determined that APS would no longer be permitted to build or own generation after 2002. During that same period, our electric reserve margins dropped from 15% to 5%. More importantly, the only option we had to meet our growing load was natural gas. Within one week of the 1999 decision, we announced our plan to build outside of APS new natural gas generation on an expedited schedule to meet anticipated load growth. Even then, APS had to lease temporary generation in 2001 when its reserve margins fell to unacceptable levels by any industry standard. The five-year dialogue on competition, competitive regional markets, regional competition plans and FERC independent scheduling organizations had reduced our practical resource options to one - natural gas. Looking forward, however, Arizona must remain committed to keeping all options open.

Rebuilding APS's financial strength to the point where it and the Commission can once again evaluate all future resource options rather than reluctantly resigning our customers to more gas-fired generation will not happen overnight. However, it will not happen, or at least will not happen in time to avoid such a one-fuel future, unless we begin now.

D. Energy Independence

Arizona has had the ability to determine its energy future in the past by aggressively making major resource additions. Most recently, when California experienced the debacle of deregulation, APS was able to meet our customer's rapidly growing needs while simultaneously reducing prices. This was possible because we had sufficient capacity that had been planned, constructed and given rate treatment over several prior years. Given the regional and interconnected nature of our electric grid, we are mutually dependent on other providers and consumers without regard to political boundaries and therefore, we must consider our demand/supply relationship over long time horizons. This necessarily places more emphasis on forecasting and the associated construction/contracting decisions. The most accurate forecasting and the most sophisticated planning processes are meaningless without action to achieve them. There must be a commitment on the part of regulators to support with positive regulatory actions the decisions that they and the utility make with regard to the direction and goals of construction/contracting decisions. Only through this common commitment can we lessen our operational dependency on the policies of other states, thus providing our state with continued energy independence.

E. Cost Management and Efficiency

We are very focused on cost management and employee productivity. As I indicated earlier, I firmly believe the Company's goals and those of this Commission are fully consistent. No place is this truer than in the areas of cost management, efficiency and productivity, and customer service. APS announced earlier this year and again very recently additional steps to reduce costs and improve efficiency. These measures, although necessary to improve cash flow and modestly improve the Company's relative financial condition, will not be sufficient to achieve the financial strength needed. Indeed, they are complementary to the interim rate relief requested in this proceeding. Even combined with such relief, APS remains in a significant, albeit improving (and that is the key thing) deficit position (see Mr. Brandt's Affidavit at 7-9).

APS realizes that this Commission wants APS to be as efficient and cost conscious as possible given the needs of reliability and customer service. I believe that the Commission's own audit of APS's fuel/purchased power procurement and handling practices, the Commissions consultants' reports on the operation of our generating facilities as part of the last rate proceeding (and thereafter, with regard to the review of 2006 outages at Palo Verde), the review of our distribution reliability and the extensive evaluations performed by Commission Staff witnesses in the hearings over the past several years all show APS is operating prudently and efficiently. That conclusion is further supported by our own internal "apples to apples" cost benchmarking data that show we consistently perform well when compared to our peers in the industry.

Finally, I would note in this regard that cost management alone will not rebuild our financial strength. Although cost management is and will remain a driving force and a core principle of this Company in mitigating the very significant effects of commodity cost inflation combined with continued growth, it cannot solely compensate for the impacts of regulatory lag. I also believe that we should avail ourselves of every cost effective tool and technology in the market that will increase efficiency and help to control costs. But this again will require a financially strong APS.

F. Reducing Rate Volatility

APS prices recently declined due to the operation of the power supply adjustment clause implemented by this Commission. We have proposed this interim price increase that would offset this decrease because it will improve APS's financial strength at this critical time, send an appropriate price signal to customers, and yet at the same time, the overall impact on our customers will be lessened. We fully appreciate the distinction between the PSA decrease and this requested interim increase. We also understand that the decline in electric rates during the winter is a regular seasonal event for most APS customers. It is not our intent to confuse one with the other. It simply is an opportunity to reduce the impact of a rate increase today as well as the impact of a final decision on the permanent rate request. No one likes to increase prices, and APS understands the effect this has on our customers. However, the impact of not increasing prices for electricity when the costs are increasing has an even greater and decidedly negative effect on customers over the long term.

IV. CONCLUSION

Q. DO YOU HAVE ANY FINAL COMMENTS?

A. Yes. In summary, this Commission should approve the interim request to (1) reduce regulatory lag; (2) send a strong message to the capital markets and to the industry as a whole that the Commission shares with APS the goal of acquiring capital at the lowest possible cost consistent with high customer service and reliability; (3) improve APS financial strength consistent with the ability to finance new base load additions; (4) maintain Arizona's energy independence; (5) support the investment necessary to improve efficiency and manage costs; and (6) minimize the impact of price increases by implementing such rates coincident with the change to winter rates in November and reducing the increase in permanent rates determined in the Company's base rate request by a like amount.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

EXHIBIT
APS-12
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01345A-08-0172

AFFIDAVIT OF DR. CHARLES J. CICCHETTI IN SUPPORT OF ARIZONA PUBLIC SERVICE COMPANY'S MOTION FOR INTERIM RATE

Charles J. Cicchetti states under oath and upon personal knowledge and belief:

A. Background and Experience

1. My name is Charles J. Cicchetti, and my business address is Pacific Economics Group, L.L.C., 301 North Lake Avenue, Suite 330, Pasadena, California 91101. I am a co-founding member of Pacific Economics Group, L.L.C.

2. Until recently, I served as the Jeffrey J. Miller Chair in Government, Business and the Economy at the University of Southern California. However, I currently continue to teach economics and public policy part time as an Adjunct Professor at that institution.

3. I actively consult on energy and environmental issues, as well as regulatory and antitrust policies, particularly as those policies relate to regulated industries.

4. I received a B.A. degree in Economics from Colorado College in 1965 and a Ph.D. degree in Economics from Rutgers University in 1969. From 1969 to 1972, I engaged in post-doctoral research at Resources for the Future.

5. I commenced my professional career in 1972 serving as the first economist for the Environmental Defense Fund (EDF), also becoming a faculty member at the University of Wisconsin from 1972 to 1985, earning the title of Professor of Economics and Environmental Studies. I resigned from my association with EDF in 1975 to serve as the Director of the Wisconsin Energy Office and as Special Energy Counselor for the Governor.

6. In 1977, Governor Patrick J. Lucey appointed me to Chair the Public Service Commission of Wisconsin ("PSCW"). I held that position until 1979 and served as Commissioner until 1980.

7. In 1980, I co-founded the Madison Consulting Group, which Marsh and McLennan Company acquired in 1984.

8. In 1984, I was named Senior Vice President of National Economic Research Associates, and held that position until 1987.

9. From 1987 until 1990, I served as Deputy Director of the Energy and Environmental Policy Center at the John F. Kennedy School of Government at Harvard University and directed the Harvard Utility Forum and the Harvard Gas Forum. During

much of this period (from 1988 to 1992), I was also a Managing Director and, ultimately, Co-Chairman of the economic and management consulting firm Putnam, Hayes & Bartlett, Inc.

10. In 1992, I formed Arthur Andersen Economic Consulting, a division of Arthur Andersen LLP. In 1996, I left Arthur Andersen to co-found Pacific Economics Group.

11. In 2002, Governor Gray Davis appointed me as a Republican member of the CAISO's Market Advisory Group.

12. In the course of my career, I have published several books and articles on energy and environmental issues, public utility regulation, natural gas pricing, competition and antitrust. I append a complete list of my publications to this affidavit as Appendix A. Additionally, I have on many occasions given expert testimony in court and administrative proceedings. I also include in Appendix A a list of the proceedings in which I have provided expert testimony since 1980. Much of this testimony concerns the regulation of electricity and natural gas pricing matters in the United States and Canada before state and provincial agencies, the Federal Energy Regulatory Commission, and the National Energy Board, as well as in judicial proceedings.

B. Introduction and Summary

13. I was asked by Arizona Public Service Company ("APS" or "Company") to opine whether, under the present circumstances, APS's request to implement a 4 mil (actually, $.003987, but I will refer to it as 4 mils for the sake of simplicity) per kWh base

rate interim surcharge, to occur coincidentally with the "roll-off" of a power supply adjustment ("PSA") charge of equal amount, would: (1) be considered as being in the public interest; and (2) constitute a reasonable ratemaking approach to the problem of APS's declining financial condition.

14. Based on my experience as outlined above and upon the information both provided by APS and that I obtained independently from public sources, I believe the answer to both of the previous questions is a decided and unequivocal "yes." I reach this conclusion for the following reasons, which I expand upon later in my affidavit and which Donald E. Brandt, President and CEO of the Company, also discusses in his affidavit:

a. APS is suffering a massive and growing earnings shortfall that is eroding its financial strength and making it increasingly difficult to attract debt and equity capital upon terms reasonable to the Company and its customers.

b. This difficulty to attract external debt and equity comes at a time when APS faces immense capital needs both for new infrastructure to serve customers and to refinance existing obligations.

c. If not a financial emergency today, this situation will likely lead to a financial emergency prior to a final order by the Arizona Corporation Commission ("Commission" or "ACC") in this docket and increases the likelihood that even a minor unforeseen negative event will precipitate a financial emergency well before that.

d. The present circumstances are beyond the Company's control and require a prompt and decisive regulatory response such as APS has requested in its Motion for Approval of Interim Rate and Preliminary Order.

e. The ACC can and should positively influence future customer rates and service by creating a situation where APS can first stabilize and then improve its debt ratings and can access additional equity capital through Pinnacle West Capital Corporation ("Pinnacle West") on non-dilutive terms.

f. The benefits to customers of improving APS's financial condition are real, substantial, and long lasting.

g. The scheduled "roll-off" of the PSA charges provides this Commission with an opportunity to address the current situation without increasing customer bills and thus act in a proactive manner, which would help customers mitigate both the effect of a final Commission decision on permanent rate relief and future rate increases that would otherwise be necessary to service more expensive APS debt and equity that would be required to pay for needed infrastructure.

h. Maintaining rates at their present level and off-setting the "roll-off" of the PSA adjustor with an interim base rate surcharge will send better price signals to customers. This would also avoid having rates fall even further below cost and avoid the "yo-yo" effect of first reducing rates just to increase them all the more upon the conclusion of the APS general rate case.

i. If lost, this opportunity will not come back again, and APS customers will face the prospect of a much larger increase in rates next year, which could be substantially mitigated by granting the Company's Motion.

C. Regulatory Perspective

15. As a new reform-minded (some might have said radical, given my prior association with EDF) utility regulator back in the mid-1970s, I came to understand that most of the outside financing necessary to provide safe, reliable, and efficient energy infrastructure came from selling new bonds, or utility debt. I quickly learned that the PSCW could favorably affect the cost of capital for Wisconsin utilities. This was also a time of escalating energy prices and consumer hardships as the nation struggled to recover from the first worldwide oil crisis and the resulting economic conditions. There was also a significant need in my state to build more and better utility infrastructure to continue to provide reliable energy supplies and to help fuel the state's economic recovery.

16. No two historical periods are ever exactly the same. Nevertheless, I am convinced that many of the enormous challenges this Commission faces today are quite similar to what my colleagues in Wisconsin and I confronted in the 1970s. That said, in my tenure at the PSCW, it quickly became apparent that, regardless of all my direct and obvious regulatory decisions, my job as a regulator also entailed keeping and striving to improve the utilities' bond ratings in the state. I soon discovered that even small shifts in fractions of percentages (called basis points, each of which is equal to .01 percent) could

directly and substantially affect the utilities' costs of service or regulated revenue requirements for decades.

17. I learned that the various utility bond ratings would adversely affect financing costs as ratings fell and, further, the amount of debt required would also likely directly increase. As is currently the case with APS, growth could not be fully financed with internal cash flow. However, if we let the gap increase relative to other businesses and were slow to respond to this obvious need, we discovered that the utilities would borrow more money and pay higher annual interest rates to finance the same infrastructure. This would cause consumers to pay more for electricity over the life of the bonds, which are quite typically 30 years.

18. This realization prompted me to conclude that you can best help consumers by being fair to shareholders and being relatively consistent and predictable. The latter meant providing a reasonable opportunity for utilities to earn their authorized rates of return. I specifically learned that when there were unavoidable lags in regulation, we could help consumers pay less over time if we approved "attrition allowances." We also made use of "make whole" adjustments to help customers pay less over time when we discovered utilities were not earning amounts somewhat comparable to their authorized returns due to rates that had become inadequate. I voted to grant relief because I found and believed that the costs associated with these short-term actions paled in comparison to the future rate increases that consumers would pay if bond ratings fell or service levels deteriorated. I also realized that it would be fundamentally wrong to set rates below the

reasonable and prudent cost of providing utility service or to permit such non-compensatory rates to continue any longer than necessary.

19. The current situation with APS is precisely the sort of circumstance where I, as a regulator, would support a means to address deteriorating financial strength with minimal impact on customers. APS has proposed precisely such a remedy in its Motion for Interim Rate.

20. As an academic, and after leaving the PSCW, I studied the details of how utility rating and other financial ratings are established. Analysts calculate various quantitative and qualitative factors. These quantitative ratios mostly compare current and projected cash flow to fixed obligations and the amount of new investments. During my tenure at the PSCW, we generally believed that we could best help consumers if we could keep these performance ratios within a tight range and responded quickly if they slipped from within that range. Fixed obligations (such as interest payments) are not discretionary. This meant that we needed to focus on internal cash flow. This Commission did that, in part, in 2007. However, APS must continue to invest more each year than it can produce internally. Conservative projections show further weakening of net cash flow. As difficult as it might seem in the short run, I believe that this Commission can save consumers a considerable amount of money in the form of lower (future) rate increases if it acts quickly and grants APS the 4 mils per kWh interim surcharge it seeks.

21. I also believed that my job as a regulator meant educating the public that the best regulatory approach was to set a "just and reasonable" return and then to take the steps necessary to assure utilities that performed prudently would very likely earn the returns authorized. Such small regulatory steps would raise rates in the near term, but still only to levels that reflect reasonable and prudent costs of providing service. Moreover, these adjustments would ease the only significant cost state regulators can pro-actively control, the cost of debt that, perhaps with the exception of fuel, is the biggest cost component of an electric utility's cost of service. In the discussion below, with respect and understanding for this Commission and its tough job in facing these daily challenges, I apply my experience and expertise as an outsider looking in on Arizona and APS.

22. APS currently has a greatly weakened financial condition due (and this is an important point) to events *it does not and cannot control.* I review some of these matters below. Most important, as Mr. Brandt has indicated in his Affidavit, APS must spend more than $1 billion in 2008 and approximately $3 billion between 2008 and 2010 on new infrastructure to enable Arizona to grow and to help ensure a reliable electricity supply for consumers. Cash flow from operations falls well short of this necessary investment. This shortfall will increase under what would be, at best, only a temporary PSA rate "roll-off" and would virtually assure that APS remains on the precipice of, and could fall to, "junk bond" status. In my opinion, the prudent regulatory response to the current situation is to replace the PSA with an equivalent base rate surcharge. In effect,

this decision would constitute a regulatory down payment on a system that will keep Arizona competitive and help APS customers to avoid paying even more for energy in the years ahead.

D. Why APS Has a Deteriorating Financial Condition that, if Left Unchecked, will Inevitably Lead to Higher Costs to Customers and, Sooner or Later, a Financial Emergency

23. At a minimum, cost-of-service regulation should provide a meaningful opportunity but not a "guarantee" under all circumstances for investors to earn the authorized return on equity ("ROE") that regulators approve in periodic rate cases. The various state utility commissions can and do differ with respect to how they apply these fundamental cost-of-service standards to particular utilities. In addition, the inadequacy of rates to recover costs under any circumstances calls for regulatory action and is an often-stubborn fact that different regulators must confront and address in a prudent manner. I apply these concepts to APS and find real financial challenges that will increase when the PSA expires, unless the Commission grants a surcharge.

24. With respect, I recommend that the Commission should grant APS's request, in effect, to offset the projected 4 mils per kWh PSA rate "roll-off" with a base rate surcharge of equal amount. APS and its customers confront very real challenges. In my opinion, these real problems negate the transient and relatively small customer benefit of a temporary drop in 2008 electricity rates.

a. APS must invest about $1 billion per year for at least the next five years in order to continue to connect new customers and provide and maintain safe, affordable, and reliable electricity, and to fuel the Arizona economy.

b. Internal operating cash flow and utility earnings are woefully insufficient to support such capital requirements. The "roll-off" of the PSA adjustor would widen the growing gap between APS's new investments and its operating cash flow.

c. Despite receiving much needed rate relief for fuel and purchased power costs in 2007, APS's actual earnings in 2007 are clearly inadequate under any circumstance, and particularly so given the new and replacement debt and equity that the Company must raise. These earnings are well below the amount authorized (10.75% ROE). Indeed, the recent rate relief was mostly focused on fuel and purchased power cost recovery, which flow through to retail customers but do not increase actual APS earnings. This is a crucial fact because, while the 2007 rate relief stopped APS's considerable bleeding of cash used to secure fuel and energy, it did not relieve APS' inherent problems related to earnings erosion and unrecovered capital costs. Indeed, from the very outset, APS has not earned its authorized rate of return under this recent rate case, and as is discussed at length in the Affidavit of Donald E. Brandt, the earnings shortfall is both massive and growing. Allowing the PSA adjustor to "roll-off" without an offsetting base rate surcharge would further weaken APS and cause it to secure new financing with considerably higher costs of capital.

d. APS's debt ratings are very poor, particularly for a utility that needs to invest more than one billion dollars per year. Specifically, the ratings are: (i) Moody's rates APS as Baa2 and its analysts view the company's outlook as "negative"; (ii) Standard & Poor's rates APS as BBB- and its analysts view the company's outlook as stable; (iii) Pinnacle West's debt ratings are a notch lower and are already "junk" grade. The danger for APS's retail customers is that a similar one notch downgrade for APS would, dependent on market conditions, add about 100 basis points to the interest needed to refinance retiring debt and to finance new infrastructure. This would require APS's customers to pay likely hundreds of millions of dollars more in the future for the same infrastructure, assuming that APS could even finance these with "junk" debt. Perhaps more importantly, at "junk" status, APS would experience the serious operational difficulties (collateral calls, loss of vendor credit, etc.) that Mr. Brandt discussed. APS would likely be shut out of the capital markets entirely during certain periods of tight credit.

e. The growth in debt expected and weak cash flow could potentially threaten bond covenants. APS would also need to generate internal equity or receive repeated infusions of equity from Pinnacle West. This will complicate financing for APS's growth without interim relief in the form of a PSA offsetting surcharge.

This would mean raising new equity capital would be more difficult and expensive, if possible at all. And, if the gap between cash flow and new investment expands, the new debt investment would likely come with higher interest rates even if credit ratings do not deteriorate.

E. Why Customers are also Facing What I Believe to be an Emergency

25. These problems and the current conditions present a <u>customer</u> emergency. Utility investors and lenders are mostly willing to match rewards and risk – an equilibrium which causes an increase in interest-related expenses when risks increase. If a state squeezes equity and regularly accepts outcomes where actual earnings fall well short of authorized amounts, utility investors are rather agnostic about taking their returns in the form of higher interest rates for downgraded debt. But the customer pays more regardless.

26. When such regulatory outcomes accompany exceptional growth, utility customers pay much more for a very long time. These higher customer costs are the result of APS's financing requirements and the amount APS must pay outside lenders both to: (a) operate the utility when current cash flow from operations is inadequate; and (b) finance the necessary utility growth with inflated interest rates relative to less risky debt. These are simply the facts and do not represent utility failures.

27. Consider APS's proposal to offset the 4 mils per kWh PSA adjustor "roll-off" later this year with an interim base rate surcharge. The intent is clear and plausible because APS seeks to avoid further earnings erosion in order to mitigate the current and

ongoing deterioration of its finances. APS makes this proposal even as the Commission is about to consider evidence in a new rate proceeding scheduled to be completed sometime in the latter half of 2009. This proposal is necessary and clearly reasonable because APS needs to continue to invest and sell debt in the remainder of 2008 and through 2009, which is the period of regulatory lag that can only be addressed through some manner of interim rate relief.

28. If the APS Motion is granted by the Commission, I conclude retail customers will actually pay less in the future regardless of the final decision in this docket concerning the establishment of permanent base rates. At best, a 4 mils per kWh rate reduction would reduce prices later this year. This would be temporary because APS is seriously under-earning and also investing in needed infrastructure that it cannot finance with internally generated cash flow. A utility company that fails to earn its authorized ROE and that nevertheless must still invest in new infrastructure will become progressively financially weaker. A retail rate reduction would certainly increase negative financial pressure. This would exacerbate the utility's weak credit ratings and further negatively influence analysts' opinions of APS.

29. The costs of debt and other sources of finance will increase. Consumers will pay higher future prices. Mr. Brandt has indicated in his Affidavit that the cost of a further downgrade of APS is more than $1 billion over just the next 10 years, which convinces me that APS's customers would be better off in terms of revenue requirements

savings if this Commission takes the long view and offsets the planned short-term PSA rate reduction with a base rate surcharge of equal amount.

30. I hasten to add that more must still be done in the new permanent rate case to ensure that improvement continues. My primary concern, and I think it should also be this Commission's primary concern, is the need to act aggressively to forestall losing current debt ratings as earnings erode further and cash outlays continue to mount as APS continues to finance growth and the ongoing cost of operations increases. In such dire and challenging circumstances, offsetting a temporary rate cut of less than $50 a year for customers using about 1,000 KWH per month with the requested interim relief seems fully justified, particularly when the beneficial effects on customers becomes a primary focus of regulation.

31. Much is at stake. Financial weakness for APS means APS customers will pay more for electricity. The state's economic growth and job creation will also suffer if prospective investors and new businesses learn or even suspect that Arizona is delaying paying for utility expansion. This could take two forms. First, a utility might sacrifice reliability and maintenance, letting trained employees leave and deferring necessary expenditures. This is not the course APS has taken, as is indicated in the Affidavit of Donald E. Brandt. If anything, there is evidence that APS is doing more with less. This means APS is working harder and smarter – but these efforts alone can never solve a regulatory problem, which is precisely what inadequate rates are.

32. A second aspect of delayed payments in the form of permanent rate relief is that it costs consumers more money in the long run if regulation, in effect, denies or softens the message of higher costs using price signals that are not predicated on the simple, conservative economic and common sense notions that growth increases costs, causes more debt, and increases the cost of fuel and purchase power. Simply selling more at unrealistic current prices does not relieve the crisis or reduce consumer costs over time.

33. Delayed utility payments are like a credit card economy. Consumers get goods and services in the near term. However, they pay more over time. Left unchecked and as consumer credit ratings fall, consumers would and do pay even more to finance the delayed payment of their purchases. Well-regulated utilities like APS hardly ever will over-spend when it comes to basics like fuel, purchase power, iron, steel, cement, meters, etc. However, they can spend more over time in credit card-like higher finance costs and, therefore, cause their customers to also spend more. Regulators should, in my opinion, recognize these realities and act in the customers' interest and on their behalf to avoid these needless additional costs.

F. Conclusion: How to Help Consumers, the State, and to Recognize Shareholders are Making Growth Possible

34. The Commission should recognize that APS has much to do to insure Arizona's continued growth and to provide safe and reliable electricity to its customers.

While APS' need to invest and spend money is great, it lacks and has lacked sufficient internal cash to fulfill its obligations.

35. I ask this Commission to consider how it could help Arizona's utility consumers to pay less over the long haul. Seldom do regulators get to address "needs" of this type or dimension without raising rates. But this Commission has such an opportunity. The Commission can continue to add to the gains made in the last rate case for fuel and purchase power without raising customer bills. Thus, the Commission could best help consumers in Arizona in the long run by granting APS's Motion, and I urge them strongly to do so.

This concludes my affidavit.

State of California)
) ss
County of Los Angeles)

I, Charles J. Cicchetti, having been duly sworn, state that I have read the foregoing affidavit and that the same is true and correct to the best of my knowledge, information, and belief.

Charles J. Cicchetti

Subscribed and sworn to me this 4th day of June, 2008.

DANIELLE NEVEU
COMM. #1710027
NOTARY PUBLIC - CALIFORNIA
LOS ANGELES COUNTY
My Comm. Expires Dec. 10, 2010

Notary Public

My Commission Expires:

Dec. 10, 2010

APPENDIX A

C.V. for Charles J. Cicchetti, Ph.D.

PROFESSIONAL EXPERIENCE

1996-present	Co-Founder, Pacific Economics Group, Pasadena, Ca and Madison, WI.
2006-present	Adjunct Professor, University of Southern California
1998-2006	Jeffrey J. Miller Professor in Government, Business, and the Economy, University of Southern California;
1990-1997	Adjunct Professor of Economics, University of Southern California;
1992-1996	Managing Director, Arthur Andersen Economic Consulting;
1991-1992	Co-Chairman, Putnam, Hayes & Bartlett, Inc.;
1988-1991	Managing Director, Putnam, Hayes & Bartlett, Inc.;
1987-1990	Deputy Director, Energy and Environmental Policy Center, John F. Kennedy School of Government, Harvard University;
1984-1987	Senior Vice President, National Economic Research Associates;
1980-1984	Co-Founder and Partner, Madison Consulting Group;
1979-1986	Professor of Economics and Environmental Studies, University of Wisconsin-Madison;
1977-1979	Chairman, Public Service Commission of Wisconsin, Appointed by Governor Patrick J. Lucey (member until 1980);
1975-1976	Director, Wisconsin Energy Office and Special Energy Counselor for Governor Patrick J. Lucey, State of Wisconsin;
1974-1979	Associate Professor, Economics and Environmental Studies, University of Wisconsin-Madison;
1972-1974	Visiting Associate Professor, Economics and Environmental Studies, University of Wisconsin-Madison;
1972	Associate Lecturer, School of Natural Resources of the University of Michigan;
1969-1972	Resources for the Future, Washington, D.C.;
1969	Ph.D., Economics, Rutgers University;
1968-1969	Instructor, Rutgers University;
1965	B.A., Economics, Colorado College;
1961-1964	Attended United States Air Force Academy.

EDITORIAL AND ADVISORY BOARDS

<u>Journal of Environmental Economics and Management</u>, Former Member
<u>Energy Systems and Policy</u>, Former Member;

Land Economics, Former Editor.
Faculty Advisor to Campus Republicans at USC, 2002 to 2005
Alliance for Energy Security; Former Member;
Association of Environmental and Resource Economics, Former Executive Committee, Former Member;
California ISO Market Advisory Group –Former Member appointed by Governor Gray Davis;
Center for Public Policy Advisory Committee, Former Member;
Department of Energy, Fuel Oil Marketing Advisory Committee, Former Member;
Graduate School of Public Policy at the University of California, Berkeley; Former Board Member;
Institute for the Study of Regulation;
National Association of Regulatory Utility Commissioners, Executive Committee and Chairman of the Ad Hoc Committee on the National Energy Act, Former Member;
Public Interest Economics Center, Board of Directors, Former Member;
Rutgers University, Energy Research Advisory Board;
U.S. Chamber of Commerce Energy and Natural Resources Committee, Former Member.

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SPEECHES

Speeches Since 1984

"Energy Efficiency and Regulatory Incentives," EUEC 11th Annual Energy and Environment Conference, Tucson, Arizona, January 27-30th, 2008.

"Conservation Reconsidered: A First Row Seat," Reconsidering "Conservation Reconsidered": A 40-Year Legacy, Resources for the Future, October 3, 2007.

"Market Issues: Power Procurement & Contracts," Law Seminars International, San Francisco, California, September 17-18th, 2007.

"Economists as Appraisers, Threats or Compliments?" Appraisal Institute Seminar, Los Angeles, California, March 26, 2007.

"The Economic Health of California's Energy Markets", An Economist's Perspective on the Electronic Health of CA Energy Markets, San Francisco, California, September 26, 2006.

"Lessons From California to Russia," Edison Electric Institute's US/Russia Electricity Markets Conference, Washington, District of Colombia, February 25, 2003.

"State Regulation Is Here to Stay: Financing the Future, " NARUC 113th Annual Convention, Philadelphia, Pennsylvania, November, 2001.

"Deregulation Revisited: The Power Crisis in California," New York University's Energy Forum, New York, New York, 26 February 2001.

"The Changing Face of Utilities," Author Anderson's 21st Annual Energy Symposium, Houston, Texas, 28 November 2000.

"Lessons for Bangladesh: Thinking Globally While Acting Locally," The World Bank's Bangladesh Power Sector Reforms Workshop, Dhaka, Bangladesh, 1 October 2000.

"Diversification and Shareholder Value," The Energy Daily's 27th Annual Conference: Lighting the World, Williamsburg, Virginia, 2 December 1999.

"Challenges for Government-Owned Utilities," The Bond Buyer Public Power Conference, Santa Monica, California, 7 October 1999.

"Restructuring America's Electricity Industry and Public Power or Customer Owned Utilities," APPA's CEO Roundtable, Scottsdale, Arizona, 3 March 1998.

"Electricity Restructuring: The Future Role of Regulation (Woulda, Shoulda, Coulda)' American Bar Association's Annual Electricity Conference, Denver, Colorado, 13 February 1998.

"Mergers in the Utility Industry," Arthur Anderson's 18th Annual Energy Symposium, Houston, Texas, 9 December 1997.

"Convergence, Competition, Mergers and Marketing: Are You Getting Ready for the Millennium?" California Foundation on the Environment and the Economy, Santa Cruz, California, 4 December 1997.

"Electric Utility Strategy: Regulation, Restructuring and Competition," The Fourth Annual Power Industry Forum: "A View Toward the New Energy Corporation," San Diego, California, 7 March 1997.

"Restructuring Energy Markets: A World Perspective," The Energy Daily's 22nd Annual Conference: The One-Stop Energy Stop, Williamsburg, Virginia, 12 December 1996.

"Mergers in the Utility Industry," Arthur Anderson's Energy Symposium, Houston, Texas, 10 December 1996.

"Political, Economic, and Regulatory Challenges when Transforming Privately-Owned Utilities to Competitive Enterprises," Presentation at the Economist Conferences, Bilbao, Spain, 12 November 1996.

"Transmission, Divestiture, and the Future," Panelist at the EEI Strategic Planning Conference, Seattle, Washington, 14 October 1996.

"Cost-of-Service Regulation: The Old Dog Won't Hunt, and Recently, It Wasn't Very Good," Presentation to the Board of Wisconsin Electric Power Company," Belize, Central America, 3 April 1996.

"Primary Mergers: An Insider's Guide," Presented at Electricity Utility Week Conference, March 15, 1996.

"Merger Policy Issues—When is a Proposed Electric Utility Merger in the Public Interest?" Panelist at the 3rd Annual DOE-NARUC National Electricity Forum, 5 December 1995.

"Measuring the Effects of Natural Resources Damage and Environmental Stigma on Property Value," Presented to Morgan, Lewis & Bockius, 29 November 1995.

"Strategy for a Natural Gas Distributor: Competition, Consolidation, Cost Cutting," for Washington Gas Light, 23 October 1995.

"Strategic Issues Facing the Electric Utility Industry," AIS Symposium, St. Charles, IL, 9 October 1995.

"Worldwide Electricity Restructuring: Regulation, Competition or Both?" presented at the 4th World Economic Development Congress, Washington, DC, 6 October 1995.

"Competition, Consolidation, Restructuring: A Program for Expanding Utility Consulting," Western Region Utility Presentation, 28 September 1995.

"North/South Estimated Savings Compared to Recent Merger Claimed Savings," for PSCo information only, July 28, 1995.

"California PUC Plans for Restructuring the Electric Industry," Utilities Overheads, 3 July 1995.

"Public Utility Holding Company Act (PUHCA) Current Issues," Utilities Overheads, 3 July 1995.

"Power Industry Restructuring: Competition and Deregulation are Not Synonyms," Utilities Overheads, 3 July 1995.

"The FERC's Role in Electric Utility Industry Restructuring," Utilities Overheads 3 July 1995.

"Whereto Regulation? Slice and Dice Supplants Command and Control," HARC Presentation, 8 August 1995/

"Strategic Issues Facing the Electric Utility Industry," US West Presentation, 1 August 1995.

"Proposal to Provide Consulting Services to Assist with An Alternative Ratemaking Proposal," Boston Gas Presentation, 27 July 1995.

"Strategic Issues Facing the Electric Utility Industry," ConEd Presentation, 26 July 1995. (Also "Power Thinking")

"Generic NU Slides"

"Strategic Issues Facing the Electric Utility Industry," NU Board of Trustee Presentation, 25 July 1995.

"Public Utility Holding Company Act (PUHCA)" Presentation to Southwest Gas Corporation, 19 June 1995.

"FERC Activity-Gas Industry Update," Presentation to Southwest Gas Corporation, 19 June 1995.

"Electric Industry Restructuring Recent FERC and CPUC Developments," Presentation to Southwest Gas Corporation, 19 June 1995.

"Power Marketing and Bulk Power Markets: Power Marketing and its Impact on the Electric Power Industry," Infocast's Power Marketing and Bulk Power Markets, 8 June 1995.

"Energy Industry in Transition," Yankee Energy Systems presentation, 23 May 1995.

"State Regulation in an Era of Regulated Competition," American Enterprise Energy Policy Forum, 16 May 1995.

"Natural Resource Damages Latest Developments and Future Focus," The CVM Controversy. Executive Enterprises NRDA Conference, 5 May 1995, San Francisco.

"Restructuring the Electric Industry," Prepared for Georgia Power Company, 28 March 1995.

"Electric, Gas and Telephone Industry Insights and Outlooks," Prepared for Peoples Energy Corporation Officers' Planning Retreat, 12 March 1995.

"The Driving Forces Reshaping the Electric Power Industry," Presentation to Northeast Utilities Management, 27 February 1995.

"Electricity Markets: Yesterday, Today, and Tomorrow," and "The Driving Forces Reshaping the Electric Power Industry," Presentation to General Electric, 13 February 1995.

"Power Marketing and Its Role in the Competitive Energy Industry: Projecting Future and International Power Needs," EEI Conference, 27 January 1995.

"Evolution or Revolution: Whoever Gets the Customers Wins!" Energy Daily Conference, 1 December 1994.

"Natural Resource Damages Latest Developments and Trends: CVM Controversy," Executive Enterprise's NRDA Conference, 15 November 1994.

"The Current Natural Gas Transportation Issues that Affect the North American Market," IGUA/ACIG Natural Gas Conference, 15 November 1994.

"Power Marketing and Its Role in the Competitive Energy Industry: Projecting Future and International Power Needs," Infocast-New York, 28 October 1994.

"FERC and State Regulatory Incentives: Restructuring the Electric Utility Industry," Arthur Andersen's Financial Symposium, 27 September 1994.

"Restructuring the Electric Utility Industry," Arthur Andersen's Financial Symposium, 27 September 1994.

"What Do We Want to Get Out of the CPUC Restructuring Process," Aspen Institute Presentation Materials, 6 July 1994.

"The Debate over Retail Competition in California: A Prescriptive Suggestion," Aspen Institute Presentation Materials, 6 July 1994.

"A Review and Critique of Internal Revenue Service Economist Report Regarding Electricity Conservation Program Expenditures and Related Tax Deductions," EEI Taxation Committee Meeting, 14 June 1994.

"The Expanding Competition in Power Markets," Environmental Law, Liability & Litigation Director's Roundtable, 18 May 1994.

"Paul Keglevic's Group Presentation to The Gas Company: Customer Values Initiative."

"NRDA and Property Valuation Analysis," presented to Fennemore Craig, P.C., 28 February 1994.

"Commentary on the Future of Regulation: Pro or Kahn?" (To Regulate or Not to Regulate: That is the Question," NARUC/DOE presentation, 15 February 1994.

"Latin America Assertion of Membership in Pacific Basin," Aspen Institute, Pac Rim Workshop, 31 January 1994.

"Utility Rate Regulation in the 1990s and Beyond," 1993 Utilities Financial Symposium, 14 September 1993.

"Natural Resource Damages: An Economic Critique," Presented to Beveridge & Diamond (w/J. Dubin), 8 September 1993.

"Understanding Economic Damage Valuations Under NRDA," Presented to Occidental USA, (w/L/ Wilde), 17 August 1993.

"Allocating Costs in Superfund Cases," Presented to Waste Management, July 1993.

"Understanding Economic Damage Valuations Under NRDA," Presented to Sidley & Austin, 29 June 1993.

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"Draft RCRA Corrective Action Regulatory Impact Analysis (RIA)," Presented to Beveridge & Diamond, 18 June 1993.

Chicago Energy Economic Association Speech, (CJC used notes/speech from UC Berkeley/RFF speech of 10 May 1993), 10 June 1993.

"Understanding Economic Damage Valuations Under NRDA," AAEC Corporate Counsel Symposium Series (Dallas & & Houston), May 18-19, 1993.

"The Regulatory Triad for the 90s: Integrated Resource Planning, Incentive, Regulation and Social Costing," UC Berkeley/RFF Briefing, 10 May 1993

"Understanding Economic Damage Valuation Under NRDA," AA/Perkins Coie Presentation, 4 May 1993.

"DSM & Shareholder Incentive," 1993 Rate Symposium, April 25-27, 1993.

"Twenty Yeats Since Earth-Day I: What Have We Learned?" USC Economic Honor Society Omicron, Delta Epsilon, 15 April 1993.

"The Clinton Economic Plan," USC Panel Discussion, 26 February 1993.

"The Good, The Bad & The Ugly," USC, 25 February 1993.

"Incorporating Externalities in Utility Least-Cost Planning," Edison Electric Institute, 10 February 1993.

"Incorporating Externalities in Utility Least-Cost Planning," A Presentation to the ABA Mid-Year Meeting, 7 February 1993.

"Understanding Economic Damage Valuations Under NRDA," Presented at "OPA-On the Gulf Coast," Seminar, sponsored by Haight, Gardner, Poor & Havens, 27 January 1993.

"DSM and Shareholders Incentives," Prepared for Southern California Edison, January 1993.

"DSM and Shareholders Incentives," Prepared for the Allied Social Science Association 1993 Annual Meetings, 5 January 1993.

"The Economic Effect of the Clean Air Act on the US Economy: Tradable Emissions Allowances," National Clean Air Conference, Houston, Texas, May 20, 1992.

"Where Do We Go From Here: Bush or Clinton?" Presented at he Corporate Recovery Conference sponsored by Arthur Andersen & Co., Scottsdale, Arizona, September 17, 1992.

"Social Cost of Electricity," Panel Discussant, Anaheim, California, January 5 & 6, 1993.

"Environmental Externalities: Are There Any Left?" American Bar Association's Winter Meeting, Boston, Massachusetts, February 7, 1993.

"Incorporating Externalities in Utility Least-Cost Planning," Edison Electric Institute Energy and Environmental Committee, San Francisco, California, February 10, 1993.

"Environmental Policy: The Good, The Bad, The Ugly," University of Southern California, Los Angeles, February 25, 1993.

"Incorporating Environmental Strategies into Your Corporation's Overall Strategy to Improve the Bottom Line," moderator, Arthur Anderson & Co's Energy 1993 Expo, Pittsburgh, Pennsylvania, March 2-3, 1993.

"Resource Planning, Incentives, and Pricing for Electric, Natural Gas, and Telecommunications Services: New Products and Regulations," University of Missouri's 1993 Rate Symposium, Kansas City, Missouri, April 26, 1993.

"Understanding Economic Damage Valuations Under Natural Resource Damage Assessments," Environmental Presentation Series with Perkins Coie, Seattle, Washington, May 4, 1993.

"The Regulatory Triad for the 90's," Resources for the Future/UC Berkeley Briefing, Berkeley, California, May 10, 1993.

"Understanding Economic Damage Valuations Under Natural Resource Damage Assessments," Arthur Andersen & Co. Corporate Counsel Symposium Series, Dallas, Texas, May 18, 1993.

"Understanding Economic Damage Valuations Under Natural Resource Damage Assessments," Arthur Andersen & Co. Corporate Counsel Symposium Series, Houston, Texas, May 19, 1993.

"An Economist's View of Demand Side Management," Chicago Energy Economists Association, Chicago, Illinois, June 10, 1993.

"Presentation to the Board of Southwest Gas," Las Vegas, Nevada, June 14, 1993.

"Draft RCRA Corrective Action Regulatory Impact Analysis (RIA)," Beveridge & Diamond, June 18, 1993-Charlie Cicchetti.

"Relative Economic Benefit as a Factor in Cost Allocation," Keck, Mahin & Cate Cost Recovery and Contribution Litigation Seminar, Chicago, Illinois, June 23, 1993.

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"National Resource Damages: What Does the Proposed Final DOI Rule Mean?", Presented at the Workshop on Natural Resource Damages, Washington, DC, May 30, 1991.

"When Green Turns Mean: Pollution as a Crime", Presented at the Third Annual Law and Economics Seminar of Putnam, Hayes & Bartlett, Inc., The Arizona Biltmore Hotel, Phoenix, Arizona, November 7-11, 1990.

"The Legal and Economic Consequences of 1992." Presented at the Second Workshop on Post Keynesian Economics, Knoxville, Tennessee, July 3, 1990.

"Environment: A Green Gimmick or a New Game Plan?", Presented at Pacific Gas & Electric Company's Managers Meeting, San Francisco, California, May 31, 1990.

"Can the Gas Business Fulfill Its New Promise?" Presented at "Inside F.E.R.C.", San Francisco, California, April 20, 1990.

"Energy Firms and Global Environmental Policy." Presented at Pacific Gas & Electric's Management Committee Retreat, Santa Cruz, California, March 17-26, 1990.

"Electric Utility Mergers and Reorganization: Antitrust Meets Regulation." Presented at the Third Annual Conference on Electric Law and Regulation, Denver, Colorado, March 9, 1990.

"Infrastructure, Regulatory, Risk/Reward Issues." Presented at the Portland General Symposium, Portland, Oregon, November 6, 1989.

"Belated and Expensive: How Utilities Have Reacted to New Economic Imperatives in the Last Two Decades," Conference Sponsored by the Energy Daily, The Watergate Hotel, Washington, D.C., November 3, 1989.

"Competitive Building: Price, Time, Location and Uncertainties." Presented at the Coopers & Lybrand Annual Electric & Gas Conference, Crystal Gateway Marriot, Arlington, VA, November 2, 1989.

"Electric Utilities: New Markets, New Challenges," Speech before the Interstate Natural Gas Association of America Seminar, The Greenbrier, White Sulphur Springs, West Virginia, October 17, 1989.

"Sweetening the Pot: Plaintiff Devices to Maximize Claims" (Contingent Value Surveys Hedonic Price Measures), Second Annual Law and Economics Seminar a Putnam, Hayes & Bartlett, Inc, The Arizona Biltmore Hotel, Phoenix, Arizona, October 11-14, 1989.

"Incentive Regulation and Conservation Policy," Presented at the New England Conference of Public Utility Commissioners, Kennebunkport, Maine, September 2, 1989.

"Incentive Regulation and Conservation Policy," Presented at the New England Conference of Public Utility Commissioners (NARUC) Least-Cost Planning Conference, Charleston, South Carolina, September 11, 1989.

"The Role of Rate Reform: The Bundling of Services," International Association of Energy Economists, North American Gas Supply and Markets Conference, The Hyatt Regency, Denver, Colorado, September 7, 1989.

"Incentive Regulation: What Works and What Doesn't." Presented at the Great Lakes Conference of Public Utility Commissioners, The Greenbrier, White Sulphur Springs, West Virginia, July 11, 1989.

"New Proposals for Incentive Regulation in the Electric Utility Industry," Chief Executives' Forum, Key Largo, Florida, Sponsored by the First Boston Corporation and Putnam, Hayes & Bartlett, Inc., February 9-12, 1989.

"Current Trends in Regulation and Some New Proposals to Alter Incentives in the Electric Utility Industry," Harvard Utility Forum Meeting, Cambridge, MA, February 1, 1989.

"Some New Proposals to Introduce Incentive Tariffs in the Electric and Natural Gas Industries," Utility Discussion Group, Held by Putnam, Hayes & Bartlett, Inc., Capital Hilton, Washington, D.C., January 5, 1989.

"Privatization in Developing Countries: Case Studies of Electricity in Turkey and Pakistan," EESIG Brown-Bag Lunch, December 14, 1988.

"Some New Proposals to Introduce Incentive Tariffs in the Electric and Natural Gas Industries," Harvard Utility Forum – Harvard Gas Forum Demand-Side Bidding/Alternatives to Rate Base Regulation Workshop, Cambridge, MA, December 13, 1988.

"The March Towards a Competitive Gas Industry: Obligation to Serve, Incentive Regulation, and Risk Allocation," The Interstate Natural Gas Association of America Seminar, Washington, D.C., December 2, 1988.

"Pricing and Contracting Issues and Experience." Presented at the AIT/ASEAN Senior Executive Seminar, Hua Hin, Thailand, November 9-11, 1988.

"Meeting the Nation's Future Electricity Needs: Cogeneration, Competition and Conservation." Presented at the 100th Annual Convention and Regulatory Symposium of the National Association of Regulatory Utility Commissioners, San Francisco, California, November 2, 1988.

Speech before the New Dimensions in Pricing Electricity Conference of Niagara Mohawk Power Corporation and the Electric Power Research Institute, "Cogeneration and Competition", Syracuse, New York, September 30, 1988.

Speech before the Second Annual Conference of the American Cogeneration Association, "Cogeneration and Competition," Chicago, Illinois, September 26, 1988.

Presentation before the American Bar Association Annual Meeting, Toronto, Ontario, Canada, August 8, 1988.

Comments Before the American Bar Association First Annual Conference on Electricity Law and Regulation, Denver, Colorado, April 7-8, 1988.

Speech at Inside F.E.R.C.'s Eight Annual Conference, "After the Chaos: Gas Strategies for the Long Term," New Orleans, Louisiana, March 21-22, 1988.

"Wholesale Electricity, Old Scar-Tissue: New Wounds Versus New Solutions," before the National Governors' Association, Washington, D.C., December 10, 1987.

"U.S. Economic Regulation of Electricity," with Miles Bidwell, NERA Seminar, London, England, June 26, 1987.

"State Regulation in the Natural Gas Revolution," presented at Proceeding of Gas Mart '87, The First National Trade Fair for Natural Gas, sponsored by Natural Gas Intelligence, Washington, D.C., May 3-5, 1987.

"Can Natural Gas Deregulation be a Model for the Electric Industry?" Speech given at the First Rutgers/New Jersey Department of Commerce Annual Conference on Energy Policy in the Middle Atlantic States, February 20, 1987 (also published in Energy Deregulation and Economic Growth).

"Marketing Strategies for Natural Gas Distributors in the 1900s," before the Gas Utility Managers Conference Sponsored by the New England Gas Association, September 7-9, 1986.

"Conservation and Cogeneration: The Utilities' Friends or Foes?" with M. Berkman, S. Curkendall and H. Parmesano, before the NERA Electric Utility Conference, Scottsdale, Arizona, February 12-15, 1986.

"The Future Competitive Environment for Utilities," remarks prepared for Dayton Power & Light Company 1985 Interdivisional Meeting, December 9, 1985.

Presentation before the Ohio Electric Association, Cincinnati, Ohio, October 23, 1985.

"The FERC's Recent Interest in Wheeling and Carriage," co-authored by Robert D. Obeiter, before the Ninth Annual News Media Seminar, Columbus, Ohio, and the Third NARUC Electric Research and Development Seminar, St. Charles, Illinois, October 22, 1985.

"The Regulatory World of Natural Gas: Are We Quitting the Game or Changing the Rules?" before the Natural Gas Supply Association 1985 Annual Meeting, Miami, Florida, October 10, 1985.

"Marginal Cost and Competition: Unbundling Natural Gas Carriage," before the Advanced Seminar in Gas Pricing Policies, Sponsored by the American Gas Association, College Park, Maryland, October 8, 1985.

"Commingling Competition with Regulation: Closing the Circle or Quitting the Game," before the Iowa Investor-Owned Utilities Management Conference, Waterloo, Iowa, October 7, 1985.

"The State Regulator in a Free Gas Market," Comments Presented at a Conference Sponsored by The Gas Daily, Chicago, Illinois, August 1985.

"Grafting Competition Onto Regulation: The Problems and The Promise," before the Iowa State Regulatory Conference, Ames, Iowa, May 1985.

"Comments Before The Workshop on Current Antitrust Issues in Public Utility Industries, sponsored by the American Bar Association, Washington, D.C., March 1985.

"Yesterday, Today and Tomorrow," Comments before the IEEE Winter Power Meeting, New York, New York, February 5, 1985.

"Natural Gas: The Eggs Have Been Scrambled, Now What?" Before the National Association for Regulatory Utility Commissioners Annual Meeting, Los Angeles, California, November 1984.

"The Performance of the Regulation of Public Utilities in the U.S., "A NERA Seminar: Is American-Style Regulation Appropriate to the UK?," London, England, October 1984.

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Before the Public Utility Commission of Oregon, Declaration of Charles J. Cicchetti and Jeffrey A. Dubin in Response to Wah Chang's Renewed, Supplemental and Alternative Motions to Compel Compliance with DR 203, In Wah Chang v PacifiCorp, UM 1002, November 19, 2007.

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Before the Public Utility Commission for the State of Oregon, Supplemental Reply Testimony of Charles J. Cicchetti, Ph.D. and Jeffrey A. Dubin, Ph.D., In Wah Chang v. PacifiCorp, Docket No. UM 1002, July 31, 2007.

Before the Oregon Public Utility Commission, Reply Testimony of Charles J. Cicchetti, Ph.D., In Wah Chang v. PacifiCorp, UM 1002, May 24, 2007.

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Before the Illinois Commerce Commission, Expert Testimony of Charles J. Cicchetti, Ph.D., On Behalf of Enbridge Energy Partners, L.P. and Enbridge Energy, Limited Partnership, Docket No. 06-0470, December 21, 2006.

Before the Alberta Energy and Utility Board, Expert Testimony of Charles J. Cicchetti, Ph.D., In Support of The Direct Energy Regulated Services Default Rate Tariff and Regulated Rate Tariff Application in 2007 and 2008, December15, 2006.

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Before the Alberta Energy and Utility Board, Expert Testimony of Charles J. Cicchetti, Ph.D., In Support of The Enmax Energy Corporation Application for Approval of a Regulated Rate Tariff (RRT) to take effect July 1, 2006, Pursuant to Section 103 of the Electric Utilities Act and Section 23 of the Regulated Rate Option Regulation, April 4, 2006.

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Before the United States District Court of Idaho, Expert Report of Charles J. Cicchetti, Ph.D. in Powerex Corp v. IDACORP Energy, L.P., Civil Case No.CV-04-441-S-EJL, October 28, 2005.

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Exhibit C

Exhibit C
INTERIM SURCHARGE SCHEDULE IR-1

APPLICATION

The Interim Base Rate Surcharge ("IR-1") shall apply to all retail electric rate schedules in accordance with their terms with the exception of Solar-2, SP-1, E-3, E-4, E-36 and Direct Access service. All provisions of the customer's current applicable rate schedule will apply in addition to this charge.

RATES

The charges shall be calculated at the following rates:

Interim Rate Charge

All kWh	$0.003987	per kWh

Arizona Public Service
AMI Plan Biannual ACC Report
September 2008

Introduction

Decision No. 68112 (Proposed Settlement Agreement, paragraph 32(e)) requires Arizona Public Service (APS) to provide the Commission with biannual reports through 2011 related to the status of APS' remote meter reading implementation. This report provides a description of the meter reading technology being installed, APS' plan for implementation, the number and type of customers involved in the program, and the costs and operational efficiencies associated with implementation. This is the sixth biannual filing addressing the status of the Advanced Metering Infrastructure (AMI) Plan and the progress since March 2008.

Overview

Since the last biannual report, APS has proceeded with its remote metering project. The number of customers with AMI smart meters has increased and APS has continued to install additional AMI meters in areas outside of metro Phoenix. AMI meters are now installed in thirty different cities and towns within the APS service territory including Yuma, Prescott Valley, and Flagstaff. Elster Electricity LLC has acquired PowerOneData Inc, the vendor that provided the first 160,000 AMI meters for the APS Smart Meter initiative. APS has awarded a contract to Elster for an additional 800,000 AMI smart meters for residential, commercial and industrial consumers. The Elster AMI System will complement the current PowerOneData (P1D) AMI system that APS has installed. APS also signed a contract with Aclara to implement its Meter Data Management System (MDMS). Aclara's Energy Prism product will be the system of record for all AMI interval usage data and be the catalyst to support a number of future programs that exploit the APS investment in AMI.

Project Status

Since the March 2008 report was last filed, APS has installed approximately 46,000 new AMI smart meters through the end of August. The installation of PowerOneData AMI meters has continued at a steady pace of approximately 7,700 meters per month. In addition, APS successfully completed a remote communication firmware upgrade to more than 100,000 P1D AMI meters. The ability to remotely upgrade firmware in the meter continues to be one of the critical requirements of any AMI system.

Through August 2008, APS completed the installation of the 154,000 P1D AMI meters. APS and Elster are currently in the process of integrating the new Elster EnergyAxis® System into the APS Customer Information System (CIS). APS plans to initiate the deployment of Elster AMI smart meters in the November time frame. Subsequent work is also underway to integrate both the P1D and Elster AMI systems with the new Aclara MDMS.

Over the last six months APS has continued to utilize AMI meters to resolve meter reading access issues as part of the Access Improvement Plan (AIP) approved by the Commission in May, 2007. As of the end of August, more than 1,150 meter reading access issues have been resolved through the use of AMI technology. As APS moves toward the larger deployment of 800,000 additional AMI meters over the next four years the majority of all meter reading access issues will be resolved.

Meter Data Management System (MDMS):

APS signed a contract with Aclara to install its MDMS product Energy Vision in 2009. APS is completing the initial requirement phase of the project and beginning the implementation plan and schedule for a long-term MDMS solution. The MDMS will provide the foundation to support future integrations with the data provided by the APS AMI systems. The MDMS will be the system of record for all interval usage data at APS. APS also selected to install the Aclara Energy Prism product which will empower customers to make more informed choices regarding the way they use and manage their electricity from aps.com. Additional features available through the MDMS include revenue protection analysis, distribution asset optimization, forecasting tools. In the future, the partnering of the Ester and Aclara products could enable APS to provide pre-paid and demand response rate offerings and similar energy conservation programs to its customers.

Elster Metering:

APS' smart meter program uses a range of Elster technologies included in its market leading EnergyAxis® System which has advanced features such as remote connect/disconnect capability, voltage monitoring to improve power quality, outage notification and both residential and commercial bidirectional meters to support net metering needs. The Elster AMI system is very similar to the P1D system. Both systems build a self configuring and self healing wireless communication networks between their meters using a 900 MHz RF radio. The Elster communication network design uses a mesh technology allowing each client meter to hop from one to another to reach a "collector" meter. The collector meter, as its name implies, collects information from each of its client meter and provides the data to the APS system through a cellular connection. This meshing approach allows an Elster collector to service up to 1,000 client meters thus reducing cellular costs to APS to communicate with the AMI meters.

The integration of the Elster technologies with the MDMS system will help APS customers monitor usage and enable APS to identify and correct service interruptions more quickly while improving efficiencies in APS meter reading, billing and customer service operations.

Deployment Plan

The AMI deployment shifted from a focus on multi-unit residential housing complexes to support the need to remove a significant number of customers off of the E-10 and EC-1 rate plans that were canceled as of July 2008. The majority of the multi-unit residential housing complexes in the Phoenix metropolitan area have now been converted to AMI meters. This focus has provided significant value in reduction of field trips. During the last six months, the AMI system has remotely processed over 57,186 service orders without a field visit.

Introducing the installation of AMI meters in residential neighborhoods in addition to addressing meter reading access issues has reduced the P1D hub to client ratio to approximately 29:1. This means that throughout the entire APS AMI meter population for each installed hub meter, there are approximately 29 client meters installed. The shift in deployment to a higher percentage of single family detached homes increases the amount of time to install each meter based on access issues and the shift from banks of meters to individual meter panels. To compensate for the reduction in the density of meters at each meter location and maintain a steady installation rate, APS has increased the size of the AMI installation team.

APS continued to successfully receive reads throughout the last six months from the AMI meters set on Neuman Peak. Based on this success APS has begun to install AMI meters on additional mountain tops within our service territory this strategy significantly increases productivity and reduces potential safety risks.

APS plans to start installing 150,000 new Elster meters in the first twelve months of deployment, beginning around November 2008. This number will subsequently increase after the successful implementation of the MDMS. By the end of 2012, APS will have added 800,000 additional meters within its service area.

Costs

This project consists of four main cost components; meters, monthly cellular communications, meter installation & administration, and building the interface with the current APS applications.

Meters:

APS has purchased an additional 24,105 AMI meters at an average cost of $93.68 per meter through August.

Communications:

APS has a contract with KORE Wireless to provide cellular service that allows the meters to communicate with APS through the Cingular cellular network. The client to hub ratio has been reduced to approximately 29:1 based on the installations of AMI meters for the Access Improvement Project (AIP) along with single family neighborhoods. The effect of reducing the client to hub ratio will slightly increase the communications cost per meter. Through February the monthly per meter communication cost was approximately $0.15. This compares with the current monthly cost per meter read of approximately $0.95 using the meter reading workforce. The cost to manually read a meter has increased slightly based on the fact that AMI meters have been installed predominately in high density areas which are the least expensive meters to read manually. While APS has reduced the cost to read meters it has also increased the value of the meter reads. Instead of receiving a single read per month from each meter, the AMI meters provide hourly reads. This interval data will provide a number of benefits for both APS and its customers once the MDMS is completed.

Meter Installation / Administration:

The AMI field operations team has installed approximately 46,000 meters in the last six months at an average cost per installed meter of approximately $11.94. When deployment progressed from high density multi-unit complexes to single family homes the cost per installation increased based on the lower density of meters as well as meter access issues.

Integration:

Over the last six months APS' integration focus has been a parallel endeavor of AMI and Meter Data Management System (MDMS), which included enhancements to existing AMI systems, a short-term integration plan for a second AMI system and the requirement phase for the MDMS. The milestones achieved include:

- Initiated development and design phase of a short-term integration for the Elster EnergyAxis® System. The short term solution will enable APS to bill from Elster meters. This will allow APS to begin deployment of Elster meters around November.
- APS has completed gathering of requirements for the initial phase of a long-term solution of the MDMS including extensive architectural discussions to ensure optimal design of the infrastructure. This effort is expected to be completed by the 2nd quarter of 2009. APS has spent approximately $247,000 for AMI integration the last six months.

Operational Efficiencies

The ability to read and program meters remotely provides immediate operational savings as well as offering the potential to significantly reduce the cost of implementing new rate designs. The table below shows the number of field visits eliminated during the last six months for customers with AMI meters. Field visits include transfer of service, meter exchanges for rate changes, and read verifies.

YYYY/MM	Transfer of Service	Rate Change & Verify	Total
2008/03	7,184	720	7,904
2008/04	7,612	826	8,438
2008/05	8,686	1,131	9,817
2008/06	9,445	1,383	10,828
2008/07	8,904	2,337	11,241
2008/08	7,861	1,090	8,951
Total	49,692	7,487	57,179

Since the inception of the AMI project, APS has completed more than 132,661 orders remotely, reducing trips to the field. Fewer trips result in reduced fuel consumption, fewer emissions and conceivably a reduction in vehicular accidents.

On May 21, 2007 the Commission approved Decision No. 69570 related to the Access Improvement Plan (AIP). One of the approved solutions to resolve meter reading access issues is to provide customers with an AMI meter that will be read remotely. In implementing this plan, APS has addressed customer access concerns, reduced estimated billing, and reduced potential safety issues by eliminating the need for meter readers to physically visit difficult to access locations. As of the end of August, more than 2,145 meter reading access issues have been resolved through the use of AMI technology, with a target of 200 more per month for the remainder of the year. As APS moves toward the larger deployment of 800,000 additional AMI meters over the next four years the majority of all meter reading access issues will be resolved.

Summary

Since the March 2008 report was last filed, APS has installed approximately 46,000 new AMI smart meters through the end of August. Additionally, APS has continued to utilize AMI meters to resolve meter reading access issues as part of the Access Improvement Plan (AIP).

In May 2008, APS awarded a contract to Elster Electricity LLC for an additional 800,000 AMI smart meters for residential, commercial and industrial customers. APS initiated the development and design phase of a short-term integration for the Elster EnergyAxis® System and as early as November 2008 plans to start installing 150,000 new Elster meters within twelve months. Elster EnergyAxis® System has advanced features such as remote connect/disconnect capability, voltage monitoring to improve power quality, outage notification and both residential and commercial bidirectional meters to support net metering needs.

APS also signed a contract with Aclara to implement and install its Meter Data Management System (MDMS) and Energy Vision in 2009. The MDMS will provide the foundation to support future integrations with the data provided by the APS AMI systems. In addition, Aclara's Energy Prism product will empower customers to make more informed choices in managing their energy through aps.com.

In the future, the partnering with the Ester and Aclara products could enable APS to provide pre-paid and demand response rate offerings and energy conservation programs to its customers.

In conclusion, APS is continuing its AMI project; deployment will move into single family detached home areas after multi-family residential complexes are saturated and APS will implement an MDMS to manage meter data from the current APS meter reading systems and provide an interface platform for any future AMI systems. APS also continues to actively monitor the AMI market for advances in technology.

The next report will be submitted in March, 2009.

EXHIBIT
APS-13
ADMITTED

REBUTTAL TESTIMONY OF CHARLES J. CICCHETTI

On Behalf of Arizona Public Service Company

Docket No. E-01345A-08-0172

(Interim Rate Request)

September 8, 2008

Table of Contents

REBUTTAL TESTIMONY OF CHARLES J. CICCHETTI
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-08-0172)
(Interim Rate Request)

I. <u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Charles J. Cicchetti, and my business address is Navigant Consulting Incorporated (NCI), 300 South Grand Avenue, Los Angeles, CA 90071. I am the same Charles J. Cicchetti who previously submitted an Affidavit in Support of Arizona Public Service Company's (APS or the Company) Motion for Interim Rate. Since submitting that Affidavit, I have joined NCI as a Senior Advisor while continuing my affiliation with Pacific Economics Group (PEG) on an interim basis.

Q. HAVE YOUR CONCLUSIONS CHANGED SINCE YOU FILED YOUR AFFIDAVIT?

A. On the bigger issues, no. I have, however, learned that the interim 4 mil Power Supply Adjustor ("PSA") ended on July 31, 2008. Therefore, it will not be possible, as I urged in my Affidavit, for the Commission to simply "roll-over" the PSA into interim rate relief through a similar surcharge or amount per kWh as the PSA.

I understand further that the Company now proposes to put the interim rate relief in effect as the Company switches from the higher summer to lower winter rates. This would help consumers adjust, although I would have preferred a simple roll-over. Nevertheless, in my experience, customers would mostly agree that waiting for the lower winter rates to come into effect would also be a useful step.

Regardless, I believe the primary reason justifying an interim rate increase remains. The significant threat of a downgrade in APS's credit ratings looms unless the Company receives meaningful interim rate relief. Such relief would also partially offset the crippling impact of regulatory lag on APS.

Q. **WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

A. I have reviewed the evidence that was submitted through Staff's consultants Mr. Ralph Smith and Mr. David Parcell, and that RUCO submitted through Mr. Stephen Ahearn. I will address in this Response why I disagree with their conclusions and continue to urge this Commission to grant APS's request for interim rate relief. By doing so, APS's declining financial condition would be addressed on an interim basis in a just and reasonable manner that would, in my opinion, advance the public interest and benefit consumers in the long run.

Q. **WHAT MATTERS ARE YOU ADDRESSING?**

A. The Staff's consultants and RUCO have raised two themes that I will address. These are: (1) there is no "emergency"; and (2) "regulatory lag" is ordinary and even beneficial. I will approach each issue as a former state utilities regulator and as a person with more than forty years of regulatory experience and expertise.

II. THE EMERGENCY ISSUE

Q. **PLEASE EXPLAIN YOUR DISAGREEMENT WITH MR. SMITH'S VIEWS ON THE EXISTENCE OF AN "EMERGENCY."**

A. I find the discussion in Mr. Smith's testimony to be a search for a single salient and dramatic event that quite literally has the financial "wolves barking at APS's door."[1] He goes on to explain that the already filed general rate case would possibly be resolved sometime in late 2009. Thus, Mr. Smith finds no emergency because APS could get away from any perceived danger in a little more than a year's time.[2]

I disagree with Mr. Smith on two levels. First, there is a ready opportunity to fix a financial problem with retail consumers paying no more than the same annual amount that they had been paying under the PSA. The current financial challenges will only get worse if not addressed before the end of 2009. The "fix" is to implement interim relief before the new rate case is decided, and this can be done without increasing rate levels beyond what they were prior to the PSA roll-off. Second, interim relief is clearly warranted from a cost-of-service standpoint and to help keep retail prices lower over time. I believe that APS should continue to invest in necessary infrastructure. Given regulatory lag, Mr. Smith suggests that APS should consider either slowing down or not completing the necessary infrastructure efforts. This would not be good for Arizona. It is also likely, with inflation of material prices, that this sort of delay would cost customers more money. Ironically, I find my conclusion to be consistent with Mr. Smith's discussion of the Net Rate Base additions and his seeming recognition that APS's rather exceptional but necessary capital expenditures would be well in excess of its cash flow from operating income (EBITDA).[3] Thus, if the "wolves" are not yet actually at the Company's door, they are certainly in the neighborhood, and they are hungry.

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[1] *See* Mr. Smith's discussion of "Alleged Emergency Circumstances" commencing on page 14 and running through page 30 of his Testimony.
[2] *See* Mr. Smith's testimony at page 30, lines 12-14.
[3] *See* Mr. Smith's Testimony at page 34, lines 4-9.

Q. HOW CAN THE COMMISSION RESOLVE THE CONFLICTING TESTIMONY AND OPINIONS EXPRESSED BY APS AND STAFF'S CONSULTANTS?

A. Obviously they need to weigh carefully the relative persuasiveness and expertise of the witnesses, but as a former regulator, I also learned the importance of thinking through matters in terms of "motive and consequences" to both consumers and the utility when competing experts or different participants in a regulatory matter took very contrary, even diametrically opposed, viewpoints. Here Staff's consultants find no immediate emergency and run off a checklist of issues that they believe proves they are correct.[4] APS and its witnesses tell a quantitative story that describes the nearly perpetual state of being "one notch away" from slipping into junk bond status according to Standard & Poors' (S&P) rating of BBB-. Staff pushes back on this observation explaining that two other rating agencies, Moody's and Fitch, give APS a bit more headroom and point to other troubled electric utilities in the nation.

Q. WHAT DO STAFF'S WITNESSES SAY ABOUT CURRENT CONDITIONS?

A. Mr. Smith and Mr. Parcell never say whether this perpetual state of financial challenge thrust upon APS is good or bad. They focus instead on whether this could be an "emergency" or not. They conclude that there is no "emergency" and, therefore, no need for interim rate relief. They fail, however, to address fully the relevant issues. APS, as Mr. Brandt explains, has significant necessary investments and faces inflated construction and material prices, which have exacerbated the negative effects of regulatory lag on APS. These combine to make it impossible to finance these capital expenditures out of operating income plus depreciation on existing infrastructure. This effort is made potentially even

[4] *See* Mr. Smith's Testimony at pages 14-30, and Mr. Parcell's Testimony at pages 9-16.

more costly and difficult because in Arizona, prudent, used and useful, necessary investments that are made before or during a general rate case begin to be depreciated before these utility investments are ever placed in Rate Base. This means that investors do not earn a portion of their return "of" these investments. In addition, there is also a zero return "on" these necessary, used and useful investments between the time they are placed into service and the future rate case when they are put into Rate Base.

Q. WHAT IS THE RELEVANCE OF THE DISTINCTION YOU DRAW BETWEEN THE RETURN "ON" AND "OF" INVESTMENTS BETWEEN RATE CASES?

A. The return "on" is the earnings on the original cost of the undepreciated investments. The return "of" original cost is synonymous with depreciation expense. This is how a regulated utility collects money to recover its principal on an investment. This depreciation or recovery "of" the original cost is the regulatory approach used to collect cash flow that can finance replacements and new investments from internal operations.

Q. ISN'T REGULATORY LAG A NORMAL PROBLEM FOR ALL UTILITIES?

A. A degree of regulatory lag is necessarily present in most jurisdictions, although usually well less than a year. The regulatory lag that has confronted APS is substantially more severe than I have seen elsewhere, does not appear to be mitigated by other ratemaking practices (e.g., attrition adjustments, interim rates, "make whole" proceedings, etc.), and is clearly detrimental to APS and its customers. These are not just normal regulatory problems for a company such as APS that needs to invest considerable amounts (in the billions of dollars) to keep up with the needs of its growing customer base. Financial analysts would and do consider these troubling signs. Financial analysts would be particularly anxious about APS if the Commission fails to grant interim rate relief given the cash-flow challenges of meeting new investments coupled with significant regulatory lag for the recovery of and return on such investments. In today's electricity industry, infrastructure delayed may also cost more to build in the future. APS is building for Arizona's future under a regulatory approach that relies on 20/20 hindsight and that often omits critical factors that increase the company's cash flow gap as it continues to build over time, and then the Company waits, with no compensation adjustment, to recover the necessary cash from customers. That is not just backward-looking, it is also decidedly not sufficient to reflect the cash flow needed and the reasonable earnings required for a utility that serves a growing service area such as the one APS serves.

Q. WOULD YOU EXPAND ON YOUR EARLIER DISCUSSION OF THE RELEVANT LESSONS YOU LEARNED AS A REGULATOR CONCERNING DISPUTES LIKE THE ONE THE COMMISSION FACES IN THIS PROCEEDING?

A. Returning to the lessons learned theme, the opposing experts and their analyses are in sharp contrast to one another. As I explained, "motives and consequences" often can help regulators cut through these technical matters when there is expert disagreement.

Although I assume both Staff's consultants and the Company witnesses have the best of motives, potential "consequences" are most important. If Staff's consultants are correct and there turns out to be no "emergency," the consequences for retail customers of granting APS's requested relief are relatively small. If APS receives interim relief, I would also expect Staff's rate case experts to urge a smaller amount of additional rate relief in late 2009 if the Commission approves the interim rate relief. Further, any interim rate relief granted would be subject to refund if found to be excessive. If the Commission determined in the (Permanent) Rate Case that the interim relief it granted was more than the rate increase it grants in the Rate Case, it could order APS to refund the amount the Commission found unwarranted, with interest. Thus, the consequences to consumers, if APS is wrong and interim rate relief was nevertheless granted, are minimal (considering that consumers are and have been receiving service below cost at current rate levels) and the Commission retains the authority to make the consumers whole if APS's interim rate relief is more than the rate relief ultimately granted in the general rate case.

Q. WHAT WOULD BE THE RESULTS IF STAFF'S CONSULTANTS' VIEWS PREVAIL, BUT THEY TURN OUT TO HAVE BEEN WRONG IN THEIR ASSESSMENT OF APS'S FINANCIAL CONDITION?

A. If the Company is correct and the Staff's consultants are wrong, there would be very different results. And none of them would be good for consumers or Arizona. Assume that the Commission does not grant interim rate relief. This would exacerbate currently soft financial conditions as APS continues to make the necessary investments without sufficient internally generated cash flow. APS would need to raise more money externally. I would expect rating agencies, including S&P, Moody's and Fitch, to either downgrade APS or at least raise enough questions to increase the cost of capital for APS and its customers. If such a downgrade occurred, retail consumers would need to pay higher prices in the future to cover the resulting higher costs of capital. APS's shareholders would not recover a reasonable return "of" the invested dollars depreciated before the next base rate case and, in my opinion, APS would fail to earn its just and reasonable authorized return "on" its investments. Worse, this vicious cycle could be viewed as a permanent condition that would mean APS customers would face the prospects of higher prices to pay for more expensive investment in the future. This means that consumers would likely be paying much more for the same services than they would otherwise have been paying had the Commission granted the interim rate relief. Worse, these needlessly higher prices will continue for many years to come.

As a former regulator, I would urge you to give considerable additional weight to my observation that the adverse consequences to APS customers of failing to act to avoid an emergency greatly exceed the consequences to those same customers of granting APS the interim rate relief requested.

III. <u>REGULATORY LAG: THE GOOD, THE BAD, AND THE UGLY</u>

Q. WHY DO YOU DISAGREE WITH MR. SMITH'S VIEWS CONCERNING THE BENEFITS OF REGULATORY LAG?

A. Mr. Smith states that "Ordinary regulatory lag does not justify APS's Requested Interim Rate Relief."[5] In this regard, Mr. Smith makes two arguments. First, he seems to conclude that the amount of money that APS is losing is just too small for there to be an emergency and, therefore, APS can postpone relief to the general rate case.[6] Second, Regulatory Lag is, in his mind and at least theoretically, a benefit that improves utility performance.[7]

I disagree with Mr. Smith on both points. I will not dwell on the numbers he discusses except to say these do not seem to be quite so trivial and to observe that he ignores the fact that without emergency rate relief: (1) new money not fully covered by operating cash flow will be invested; (2) cash flow will decline; and (3) the negative effect on APS will increase until at least the end of 2009. These are the very matters that analysts, who determine APS's ratings and thus

[5] *See* Mr. Smith's Testimony at pages 11-14.
[6] *See* Mr. Smith's Testimony at page 14, lines 15-19.
[7] *See* Mr. Smith's Testimony at page 12, line 23 through page 13 line 17.

the cost of capital consumers will pay in the years ahead, have already told us are the very things that they will be following carefully.

Q. WHAT ARE SOME OF THE RELEVANT PARTICULARS AT THIS TIME CONFRONTING APS?

A. Some of the salient particulars are that Mr. Smith thinks APS overstates its arguments because about $297 million of capital expenditures occur after December 31, 2007 and would not be in the historic test year filed in 2008.[8] He also thinks that APS would recover cash from depreciation expenses, and he argues that the amount of new Rate Base would "only" increase about $538 million at the end of the December 31, 2007 test year for the "New" general rate case.[9]

As I count these two effects, Mr. Smith is saying that sometime in 2008, APS has about $835 million in likely-to-be-prudent utility investments that it would not receive a return "on" or "of" until the end of 2009, at the earliest. At that time, as I understand Mr. Smith's approach to regulation, which is predicated in part on the efficacy of his "good" regulatory lag, $297 million (plus the additional amounts invested later in 2008 and 2009) would still not be included in Rate Base until yet another subsequent rate case.

Taking a very conservative fraction of the conservative $835 million in new investments not included in Rate Base to recover depreciation, property taxes, and a return would, in my experience, result in increased annual revenue requirements of about $170 million, give or take $10 million. Mr. Smith seems to think that regulatory lag will result in a temporary delay in APS recovering

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[8] *See* Mr. Smith's Testimony at page 12, lines 5-6.
[9] *See* Mr. Smith's Testimony at page 12, lines 16-20.

this revenue. He is mistaken. This loss in revenue is permanent. APS will never be able to recover the full original cost of its capital expenditures. Further, some of the future authorized return "on" that now depreciated investment would, in effect, be needed to repay the portion of the investment "of" that would be lost to such depreciation during the period of regulatory lag. There are no regulatory provisions in Arizona, as far as I understand things, to recover lost depreciation or even the higher property taxes paid in the period between rate cases. Again, and contrary to Mr. Smith's implication, these losses are permanent to APS. Further, these lost recovery opportunities are nearly fifty percent more than the $115 million in interim rate relief APS seeks. These foregone cost recoveries are neither "too small" to matter, in my opinion, nor do they represent mere "timing" differences.

Q. DOES REGULATORY LAG PRODUCE "GOOD" EFFECTS FOR ARIZONA?

A. No. Mr. Smith seems to believe these massive losses will do some "good" in the form of encouraging more management emphasis on "cost control" than would be the case if consumers paid for "plant additions during the periods between rate cases."[10] He also opines that regulatory lag could cause a utility to question whether it might "be prudent to delay or avoid the related capital expenditures."[11]

APS is a rather uniquely high growth utility that struggles perpetually to stretch thin cash flow against the stark reality of high capital expenditure requirements. Mr. Smith's notion that APS consider cutting back on capital expenditures to serve customers would negatively affect service, could well lead to higher costs

[10] *See* Mr. Smith's Testimony at page 13, lines 5-8.
[11] *See* Mr. Smith's Testimony at page 13, line 13.

in the future, and would likely have a negative effect on Arizona's economy, especially in light of the recent mortgage, housing, and construction slowdown.

Q. ARE THERE ANY "BAD" EFFECTS?

A. This severe gap is bad for shareholders, and it also means higher cost of capital for retail consumers in Arizona. There is nothing "good" about this severe gap. Indeed, these bad things are exacerbated further because Arizona uses an historic test year in an environment of high growth and high capital outlay requirements. As I understand rate cases in Arizona, the Commission can adjust for "known" changes between test years, but that such adjustments are discretionary and are often highly contested. Accordingly, there is a strong element of risk involved and typically no use of prospective attrition adjustments or after-the-fact "make-whole" relief in recent years. Thus, APS forfeits the recovery "of" depreciation and return "on" plant placed in service and used to serve customers between rate cases.

APS is constantly challenged to stay ahead of the curve because of regulatory lag in Arizona. Regulatory lag is especially bad for a utility, like APS, that is forced to spend substantial amounts to accommodate the growth on its system. Regulatory lag is "bad" when it forces a utility constantly to seek relief from its Commission. It is bad for consumers to receive delayed and watered down price signals because this can influence consumption decisions. It is also bad for consumers if the result is a weakened utility. In my opinion, the Commission should balance the interests of both shareholders and consumers by providing APS with a greater cushion against the possibility of a "junk" debt rating, rather than providing APS with the bare minimum it needs to maintain its current minimum investment grade rating. This should prove to be a "win-win" for both

APS and its customers in the long term because it would lower the cost of capital and benefit consumers for decades to come.

Q. DO YOU AGREE WITH RUCO WITNESS MR. AHEARN'S CONCLUSION THAT REGULATION IN ARIZONA "HAS WORKED FAIRLY AND RATIONALLY FOR DECADES"[12] AND THAT APS IS ATTEMPTING TO REDEFINE THE "REGULATORY PARADIGM IN ARIZONA."[13]

A. No. I do not agree that the examples he cites of state regulations or policies that other states have used are in any respect unfair, unjust, or irrational. Indeed, I have been involved in regulation for more than four decades, and I am very familiar with regulatory practices that include: automatic adjustors, interim/emergency rates; single issue ratemaking; decoupling mechanisms, and "ACRM-like mechanisms." Mr. Ahearn condemns each of these as creating a "new regulatory system" that would shift risk to ratepayers.[14]

I strongly disagree that this is what other state Commissions have done when they sometimes approve or adopt such mechanisms. More important, I believe that when state regulators have ordered utilities to use such regulatory mechanisms, they do so to reduce future regulated utility prices and/or to promote the public interest.

Q. WHAT WOULD IT TAKE FOR THESE EFFECTS OF REGULATORY LAG TO TURN "UGLY"?

A. The "ugly" face of regulatory lag has not occurred in Arizona. And by "ugly," I mean a downgrade of APS to "junk" and a resulting inability to finance needed infrastructure at a reasonable cost. This would result from a losing struggle between necessary APS construction confronting insufficient cash flow and no

[12] *See* Mr. Ahearn's Testimony at page 7 line 1.
[13] *See* Mr. Ahearn's Testimony at page line 23.
[14] *See* Mr. Ahearn's Testimony at page 7, lines 1-5.

or unduly delayed rate relief. Again, the likely outcome would be the lowering of bond ratings to junk status and higher future costs of capital resulting in higher retail prices in Arizona. Quite simply, there is no "good" regulatory lag when the Company has to recover large capital expenses to meet its customers growing needs and to ensure system reliability.

IV. CONCLUSION

Q. WHAT SHOULD THIS COMMISSION TAKE AWAY FROM YOUR TESTIMONY?

A. Mr. Ahern concludes these are not extraordinary times; therefore, do not grant "extraordinary relief" or allow "non-traditional ratemaking."[15] I think that APS's growth and infrastructure investment requirements in today's global environment are extraordinary. The financial analysts and rating agencies have granted APS a bit of a reprieve, but they are poised to act to downgrade APS's bonds if they see signs that the Commission does not appreciate APS's financial problems due to inadequate cash flow, significant new investments, and a regulatory lag that does not and cannot make APS whole.

I urge the Commission to fix this immediate problem with interim rate relief before it becomes a crisis. In effect, it is better to evacuate when there are storm warnings than to try and ride out the impending storm, let alone clean up after. Staff's consultants and RUCO either ignore the warnings or believe the Commission should wait for the storm to hit. This would not be prudent, and it is not good for consumers. The Commission can act before the next rate case is decided without raising prices above the level they were this past July. I urge it to do so.

[15] *See* Mr. Ahearn's Testimony at page 7, lines 13-15.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

EXHIBIT
APS-14
ADMITTED

STANDARD & POOR'S

RATINGSDIRECT®

June 2, 2004

New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised

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Table Of Contents

New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised

Standard & Poor's Ratings Services has assigned new business profile scores to U.S. utility and power companies to better reflect the relative business risk among companies in the sector. Standard & Poor's also has revised its published risk-adjusted financial guidelines. The new business scores and financial guidelines do not represent a change to Standard & Poor's ratings criteria or methodology, and no ratings changes are anticipated from the new business profile scores or revised financial guidelines.

New Business Profile Scores and Revised Financial Guidelines

Standard & Poor's has always monitored changes in the industry and altered its business risk assessments accordingly. This is the first time since the 10-point business profile scale for U.S. investor-owned utilities was implemented that a comprehensive assessment of the benefits and the application of the methodology has been made. The principal purpose was to determine if the methodology continues to provide meaningful differentiation of business risk. The review indicated that while business profile scoring continues to provide analytical benefits, the complete range of the 10-point scale was not being utilized to the fullest extent.

Standard & Poor's has also revised the key financial guidelines that it uses as an integral part of evaluating the credit quality of U.S. utility and power companies. These guidelines were last updated in June 1999. The financial guidelines for three principal ratios (funds from operations (FFO) interest coverage, FFO to total debt, and total debt to total capital) have been broadened so as to be more flexible. Pretax interest coverage as a key credit ratio was eliminated.

Finally, Standard & Poor's has segmented the utility and power industry into sub-sectors based on the dominant corporate strategy that a company is pursuing. Standard & Poor's has published a new U.S. utility and power company ranking list that reflects these sub-sectors.

There are numerous benefits to the reassessment. Fuller utilization of the entire 10-point scale provides a superior relative ranking of qualitative business risk. A simultaneous revision of the financial guidelines supports the goal of not causing rating changes from the recalibration of the business profiles. Classification of companies by sub-sectors will ensure greater comparability and consistency in ratings. The use of industry segmentation will also allow more in-depth statistical analysis of ratings distributions and rating changes.

The reassessment does not represent a change to Standard & Poor's criteria or methodology for determining ratings for utility and power companies. Each business profile score should be considered as the assignment of a new score; these scores do not represent improvement or deterioration in our assessment of an individual company's business risk relative to the previously assigned score. The financial guidelines continue to be risk-adjusted based on historical utility and industrial medians. Segmentation into industry sub-sectors does not imply that specific company characteristics will not weigh heavily into the assignment of a company's business profile score.

Results

Previously, 83% of U.S. utility and power business profile scores fell between '3' and '6', which clearly does not reflect the risk differentiation that exists in the utility and power industry today. Since the 10-point scale was introduced, the industry has transformed into a much less homogenous industry, where the divergence of business risk--particularly regarding management, strategy, and degree of competitive market exposure--has created a much wider spectrum of risk profiles. Yet over the same period, business profile scores actually converged more tightly around a median score of '4'. The new business profile scores, as of the date of this publication, are shown in Chart 1. The overall median business profile score is now '5'.

Chart 1

Table 1 contains the revised financial guidelines. It is important to emphasize that these metrics are only guidelines associated with expectations for various rating levels. Although credit ratio analysis is an important part of the ratings process, these three statistics are by no means the only critical financial measures that Standard & Poor's uses in its analytical process. We also analyze a wide array of financial ratios that do not have published guidelines for each rating category.

Table 1

Revised Financial Guidelines								
Funds from operations/interest coverage (x)								
Business Profile	**AA**		**A**		**BBB**		**BB**	
1	3	2.5	2.5	1.5	1.5	1		

Table 1

Revised Financial Guidelines (cont.)

2	4	3	3	2	2	1		
3	4.5	3.5	3.5	2.5	2.5	1.5	1.5	1
4	5	4.2	4.2	3.5	3.5	2.5	2.5	1.5
5	5.5	4.5	4.5	3.8	3.8	2.8	2.8	1.8
6	6	5.2	5.2	4.2	4.2	3	3	2
7	8	6.5	6.5	4.5	4.5	3.2	3.2	2.2
8	10	7.5	7.5	5.5	5.5	3.5	3.5	2.5
9			10	7	7	4	4	2.8
10			11	8	8	5	5	3

Funds from operation/total debt (%)

Business Profile	AA		A		BBB		BB	
1	20	15	15	10	10	5		
2	25	20	20	12	12	8		
3	30	25	25	15	15	10	10	5
4	35	28	28	20	20	12	12	8
5	40	30	30	22	22	15	15	10
6	45	35	35	28	28	18	18	12
7	55	45	45	30	30	20	20	15
8	70	55	55	40	40	25	25	15
9			65	45	45	30	30	20
10			70	55	55	40	40	25

Total debt/total capital (%)

Business Profile	AA		A		BBB		BB	
1	48	55	55	60	60	70		
2	45	52	52	58	58	68		
3	42	50	50	55	55	65	65	70
4	38	45	45	52	52	62	62	68
5	35	42	42	50	50	60	60	65
6	32	40	40	48	48	58	58	62
7	30	38	38	45	45	55	55	60
8	25	35	35	42	42	52	52	58
9			32	40	40	50	50	55
10			25	35	35	48	48	52

Again, ratings analysis is not driven solely by these financial ratios, nor has it ever been. In fact, the new financial guidelines that Standard & Poor's is incorporating for the specified rating categories reinforce the analytical framework whereby other factors can outweigh the achievement of otherwise acceptable financial ratios. These factors include:

- Effectiveness of liability and liquidity management;
- Analysis of internal funding sources;
- Return on invested capital;

- The record of execution of stated business strategies;
- Accuracy of projected performance versus actual results, as well as the trend;
- Assessment of management's financial policies and attitude toward credit; and
- Corporate governance practices.

Charts 2 through 6 show business profile scores broken out by industry sub-sector. The five industry sub-sectors are:

- Transmission and distribution--Water, gas, and electric;
- Transmission only--Electric, gas, and other;
- Integrated electric, gas, and combination utilities;
- Diversified energy and diversified nonenergy; and
- Energy merchant/power developer/trading and marketing companies.

Chart 2

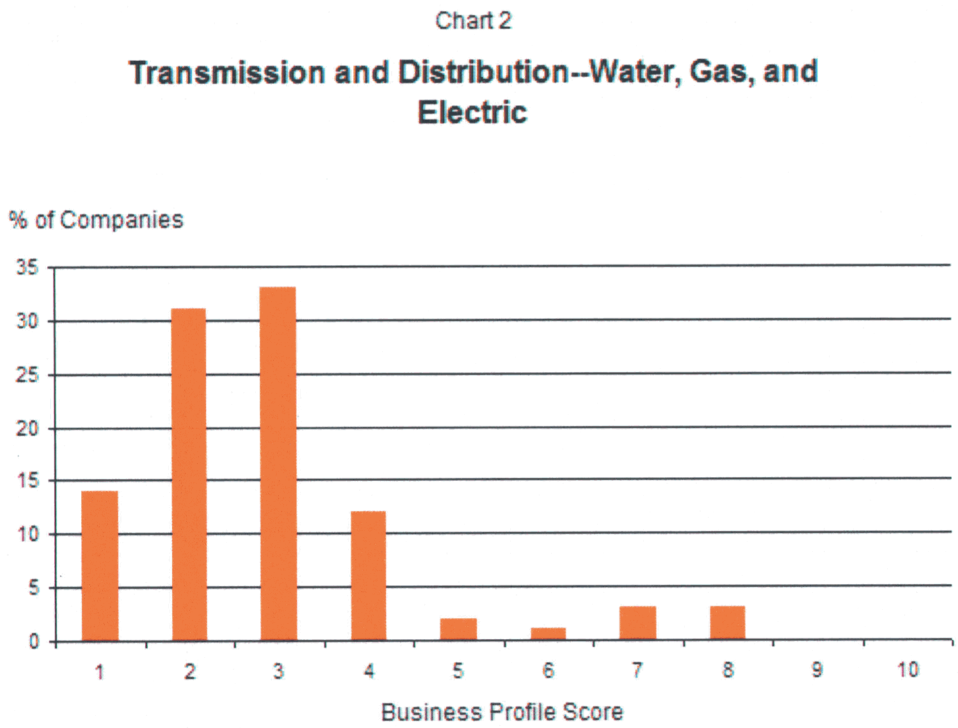


Chart 3

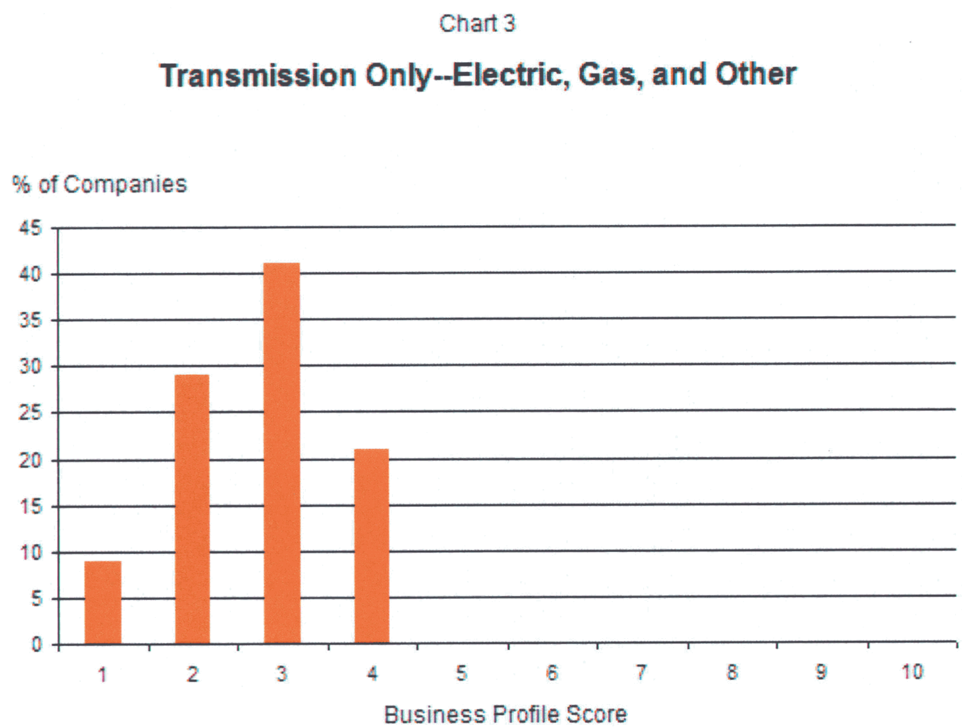


Chart 3
Transmission Only--Electric, Gas, and Other
% of Companies
45
40
35
30
25
20
15
10
5
0
1
2
3
4
5
6
7
8
9
10
Business Profile Score

Chart 4

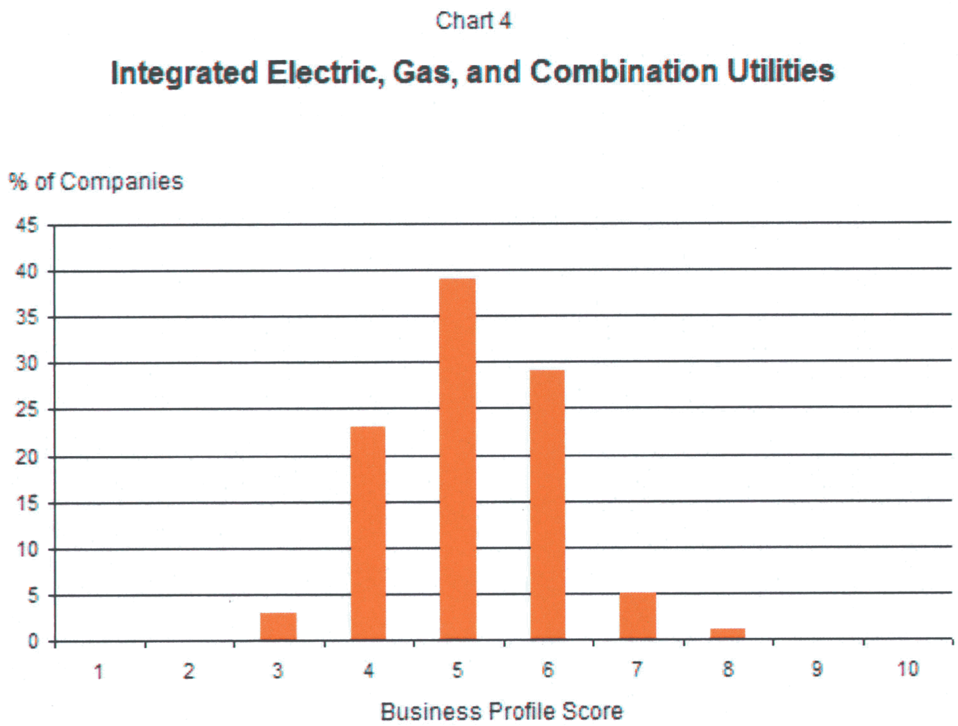


Chart 4
Integrated Electric, Gas, and Combination Utilities
% of Companies
45
40
35
30
25
20
15
10
5
0
1
2
3
4
5
6
7
8
9
10
Business Profile Score

Chart 5

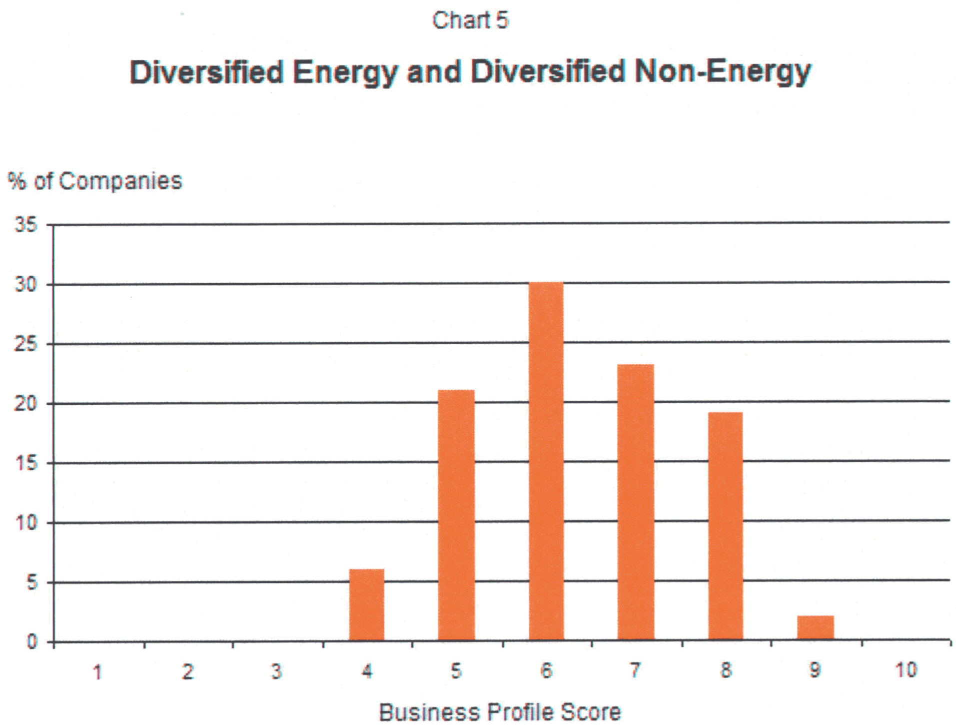
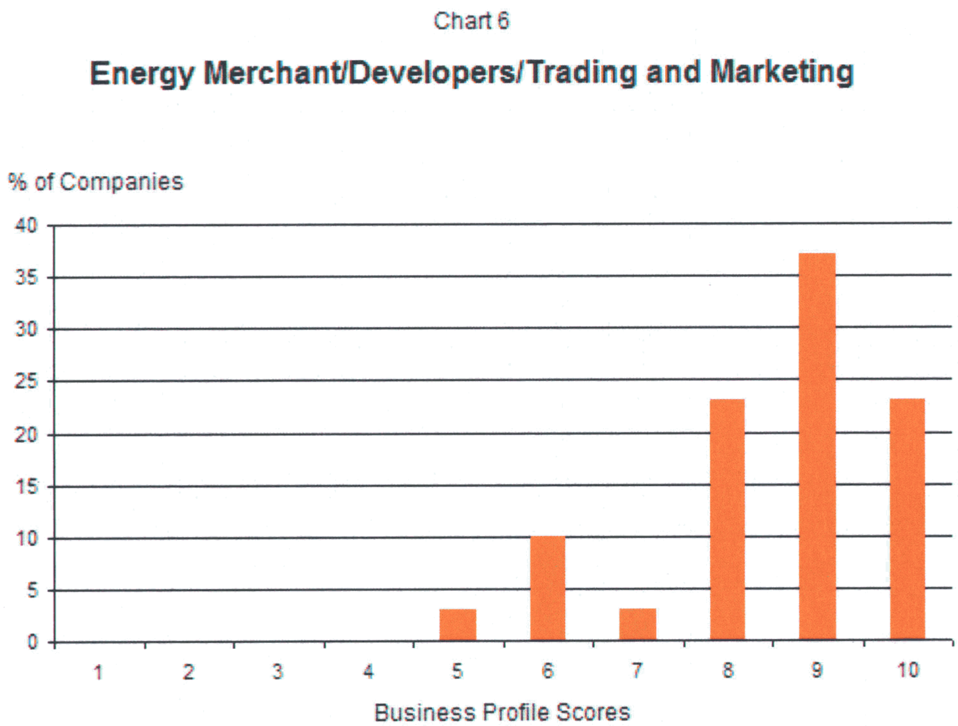


Chart 5
Diversified Energy and Diversified Non-Energy
% of Companies
35
30
25
20
15
10
5
0
1
2
3
4
5
6
7
8
9
10
Business Profile Score

Chart 6



The average business profile scores for transmission and distribution companies and transmission-only companies are lower on the scale than the previous averages, while the average business profile scores for integrated utilities, diversified energy, and energy merchants and developers are higher.

The Appendix provides the company list of business profile scores segmented by industry sub-sector and ranked in order of credit rating, outlook, business profile score, and relative strength.

Business Profile Score Methodology

Standard & Poor's methodology of determining corporate utility business risk is anchored in the assessment of certain specific characteristics that define the sector. We assign business profile scores to each of the rated companies in the utility and power sector on a 10-point scale, where '1' represents the lowest risk and '10' the highest risk. Business profile scores are assigned to all rated utility and power companies, whether they are holding companies, subsidiaries or stand-alone corporations. For operating subsidiaries and stand-alone companies, the score is a bottom-up assessment. Scores for families of companies are a composite of the operating subsidiaries' scores. The actual credit rating of a company is analyzed, in part, by comparing the business profile score with the risk-adjusted financial guidelines.

For most companies, business profile scores are assessed using five categories; specifically, regulation, markets, operations, competitiveness, and management. The emphasis placed on each category may be influenced by the dominant strategy of the company or other factors. For example, for a regulated transmission and distribution company, regulation may account for 30% to 40% of the business profile score because regulation can be the single-most important credit driver for this type of company. Conversely, competition, which may not exist for a transmission and distribution company, would provide a much lower proportion (e.g., 5% to 15%) of the business profile score.

For certain types of companies, such as power generators, power developers, oil and gas exploration and production companies, or nonenergy-related holdings, where these five components may not be appropriate, Standard & Poor's will use other, more appropriate methodologies. Some of these companies are assigned business profile scores that are useful only for relative ranking purposes.

As noted above, the business profile score for a parent or holding company is a composite of the business profile scores of its individual subsidiary companies. Again, Standard & Poor's does not apply rigid guidelines for determining the proportion or weighting that each subsidiary represents in the overall business profile score. Instead, it is determined based on a number of factors. Standard & Poor's will analyze each subsidiary's contribution to FFO, forecast capital expenditures, liquidity requirements, and other parameters, including the extent to which one subsidiary has higher growth. The weighting is determined case-by-case.

Appendix: U.S. Utility and Power Company Ranking List

U.S. Utility and Power Company Ranking List

Company	Corporate Credit Rating	Business Profile
1. Regulated Transmission and Distribution - Electric, Gas, and Water		
Baton Rouge Water Works Co. (The)	AA/Stable/--	1
Nicor Gas Co.	AA/Stable/A-1+	2
Nicor Inc.	AA/Stable/A-1+	3
Washington Gas Light Co.	AA-/Stable/A-1+	2
WGL Holdings Inc.	AA-/Stable/A-1+	3
New Jersey Natural Gas Co.	A+/Stable/A-1	1
Aqua Pennsylvania	A+/Stable/--	2
KeySpan Energy Delivery Long Island	A+/Negative/--	1
KeySpan Energy Delivery New York	A+/Negative/--	1
Elizabethtown Water Co.	A+/Negative/--	2
California Water Service Co.	A+/Negative/--	3
Questar Gas Co.	A+/Negative/--	3
Southern California Gas Co.	A/Stable/A-1	1
Boston Edison Co.	A/Stable/A-1	1
Commonwealth Electric Co.	A/Stable/--	1
Cambridge Electric Light Co.	A/Stable/--	1
NSTAR	A/Stable/A-1	1
Massachusetts Electric Co.	A/Stable/A-1	1
Narragansett Electric Co.	A/Stable/A-1	1
Northwest Natural Gas Co.	A/Stable/A-1	1
Connecticut Water Service Inc.	A/Stable/ --	2
Connecticut Water Co. (The)	A/Stable/ --	2

U.S. Utility and Power Company Ranking List (cont.)		
Aquarion Co.	A/Stable/--	2
Aquarion Water Co. of Connecticut	A/Stable/--	2
NSTAR Gas Co.	A/Stable/--	2
Piedmont Natural Gas Co. Inc.	A/Stable/A-1	2
National Grid USA	A/Stable/A-1	2
Consolidated Edison Co. of New York Inc.	A/Stable/A-1	2
Orange and Rockland Utilities Inc.	A/Stable/A-1	2
Rockland Electric Co.	A/Stable/--	2
Consolidated Edison Inc.	A/Stable/A-1	2
Laclede Gas Co.	A/Stable/A-1	3
Laclede Group Inc.	A/Stable/--	3
Atlantic City Sewerage Co.	A/Stable/--	3
Niagara Mohawk Power Corp.	A/Stable/--	3
Central Hudson Gas & Electric Co.	A/Stable/--	3
American Water Capital Corp.	A/Negative/	2
Boston Gas Co.	A/Negative/--	2
Colonial Gas Co.	A/Negative/--	2
Middlesex Water Co.	A/Negative/--	3
York Water Co. (The)	A-/Stable/--	2
Alabama Gas Corp.	A-/Stable/--	2
Atlanta Gas Light Co.	A-/Stable/--	2
Public Service Co. of North Carolina Inc.	A-/Stable/A-2	2
Wisconsin Gas Co.	A-/Stable/A-2	2
North Shore Gas Co.	A-/Stable/A-2	2
Peoples Gas Light & Coke Co.	A-/Stable/A-2	2
ONEOK Inc.	A-/Stable/A-2	6
Indiana Gas Co. Inc.	A-/Negative/--	1
Southern California Water Co.	A-/Negative/--	3
American States Water Co.	A-/Negative/--	3
United Water New Jersey	A-/Negative/--	4
United Waterworks	A-/Negative/--	4
PPL Electric Utilities Corp.	A-/Negative/--	4
Commonwealth Edison Co.	A-/Negative/A-2	4
PECO Energy Co.	A-/Negative/A-2	4
Central Illinois Public Service Co.	A-/CW-Neg/--	3
Western Massachusetts Electric Co.	BBB+/Stable/--	1
Cascade Natural Gas Corp.	BBB+/Stable/--	2
South Jersey Gas Co.	BBB+/Stable/--	2
Baltimore Gas & Electric Co.	BBB+/Stable/A-2	3
Connecticut Natural Gas Corp.	BBB+/Negative/--	3
Southern Connecticut Gas Co.	BBB+/Negative/--	3
Central Maine Power Co.	BBB+/Negative/--	3
Atlantic City Electric Co.	BBB+/Negative/A-2	3

U.S. Utility and Power Company Ranking List (cont.)		
Potomac Electric Power Co.	BBB+/Negative/A-2	3
Delmarva Power & Light Co.	BBB+/Negative/A-2	3
Yankee Gas Services Co.	BBB+/Negative/--	3
Connecticut Light & Power Co.	BBB+/Negative/--	3
UGI Utilities Inc.	BBB+/Negative/--	4
Bay State Gas Co.	BBB/Stable/--	2
AEP Texas Central Co.	BBB/Stable/--	2
AEP Texas North Co.	BBB/Stable/--	2
Southwest Gas Corp.	BBB-/Stable/--	3
Columbus Southern Power Co.	BBB/Stable/--	3
Ohio Power Co.	BBB/Stable/--	3
Public Service Electric & Gas Co.	BBB/Stable/A-2	3
Oncor Electric Delivery Co.	BBB/Negative/--	2
Southern Union Co.	BBB/Negative/--	3
Centerpoint Energy Houston Electric LLC	BBB/Negative/--	3
CenterPoint Energy Resources Corp.	BBB/Negative/--	3
Duquesne Light Co.	BBB/Negative/	4
Duquesne Light Holdings Inc.	BBB/Negative/ --	5
TXU Gas Co.	BBB/CW-Dev/--	3
Jersey Central Power & Light Co.	BBB-/Stable/--	4
Metropolitan Edison Co.	BBB-/Stable/--	4
Pennsylvania Electric Co.	BBB-/Stable/--	4
Texas-New Mexico Power Co.	BB+/Stable/--	4
AmeriGas Partners L.P.	BB+/Stable/--	7
NUI Utilities Inc.	BB/CW-Dev/--	4
Suburban Propane Partners L.P.	BB-/Stable/--	8
Star Gas Partners L.P.	BB-/Stable/--	8
SEMCO Energy Inc.	BB-/Negative/--	5
Ferrellgas Partners L.P.	BB-/Negative/--	8
Potomac Edison Co.	B/Stable/--	3
West Penn Power Co.	B/Stable/--	3
Illinova Corp.	B/Negative/--	7
NorthWestern Corp.	D/NM/--	7
2. Transmission Only - Electric, Gas, and Other		
Questar Pipeline Co.	A+/Negative/--	3
Mid-West Independent Transmission System Operator Inc.	A/Stable/--	1
American Transmission Co.	A/Stable/A-1	1
New England Power Co.	A/Stable/A-1	1
Colonial Pipeline Co.	A/Stable/A-1	3
Dixie Pipeline Co.	--/--/A-1	3
Plantation Pipeline Co.	--/--/A-1	3
Explorer Pipeline Co.	A/Stable/A-1	4

U.S. Utility and Power Company Ranking List (cont.)		
Northern Natural Gas Co.	A-/Positive/--	2
Buckeye Partners L.P.	A-/Stable/--	4
Kern River Gas Transmission Co.	A-/Negative/--	3
Northern Border Pipeline Co.	A-/CW-Neg/--	2
Texas Gas Transmission LLC	BBB+/Stable/--	3
Iroquois Gas Transmission System L.P.	BBB+/Stable/--	3
Florida Gas Transmission Co.	BBB/Stable/--	2
International Transmission Co.	BBB/Stable	2
ITC Holding Corp.	BBB/Stable	2
Texas Eastern Transmission L.P.	BBB/Stable/--	3
PanEnergy Corp.	BBB/Stable/--	3
TE Products Pipeline Co. L.P.	BBB/Stable/--	4
TEPPCO Partners L.P.	BBB/Stable/--	4
Panhandle Eastern Pipeline LLC	BBB/Negative/--	3
Noark Pipeline Finance LLC	BBB/Negative/--	4
Southern Star Central Gas Pipeline Inc.	BB/Stable/--	3
Transwestern Pipeline Co.	BB/CW-Dev/--	4
Transcontinental Gas Pipe Line Corp.	B+/Negative/--	2
Northwest Pipeline Corp.	B+/Negative/--	2
Colorado Interstate Gas Co.	B-/Negative/--	2
Southern Natural Gas Co.	B-/Negative/--	2
ANR Pipeline Co.	B-/Negative/--	3
Tennessee Gas Pipeline Co.	B-/Negative/--	3
El Paso Tennessee Pipeline Co.	B-/Negative/--	3
El Paso Natural Gas Co.	B-/Negative/--	4
Gas Transmission-Northwest Corp.	CC/CW-Pos/--	2
3. Integrated Electric, Gas, and Combination Utilities		
Wisconsin Public Service Corp.	AA-/Stable/A-1+	4
Madison Gas & Electric Co.	AA/Negative/A-1+	4
Southern Co.	A/Stable/A-1	4
Georgia Power Co.	A/Stable/A-1	4
Alabama Power Co.	A/Stable/A-1	4
Mississippi Power Co.	A/Stable/A-1	4
Gulf Power Co.	A/Stable/--	4
Savannah Electric & Power Co.	A/Stable/--	4
San Diego Gas & Electric Co.	A/Stable/A-1	5
MidAmerican Energy Co.	A/Stable/A-1	5
Questar Corp.	--/--/A-1	6
Equitable Resources Inc.	A/Stable/A-1	6
Florida Power & Light Co.	A/Negative/A-1	4
South Carolina Electric & Gas Co.	A-/Stable/A-2	4
SCANA Corp.	A-/Stable/--	4

U.S. Utility and Power Company Ranking List (cont.)		
Wisconsin Electric Power Co.	A-/Stable/A-2	4
AGL Resources Inc.	A-/Stable/A-2	4
Virginia Electric & Power Co. (Dominion Virginia)	A-/Stable/A-2	5
Idaho Power Co.	A-/Stable/A-2	5
IDACORP Inc.	A-/Stable/A-2	5
Energen Corp.	A-/Stable/--	6
Vectren Utility Holdings Inc.	A-/Negative/A-2	3
Wisconsin Power & Light Co.	A-/Negative/A-2	4
Atmos Energy Corp.	A-/Negative/A-2	4
Southern Indiana Gas & Electric Co.	A-/Negative/--	5
Montana-Dakota Utilities Co.	A-/Negative/--	5
PacifiCorp	A-/Negative/A-2	5
Northern Border Partners L.P.	A-/CW-Neg/--	4
Central Illinois Light Co.	A-/CW-Neg/--	5
CILCORP	A-/CW-Neg/--	5
Union Electric Co.	A-/CW-Neg/A-2	5
Ameren Corp.	A-/CW-Neg/A-2	5
Cincinnati Gas & Electric Co.	BBB+/Stable/A2-	4
Oklahoma Gas & Electric Co.	BBB+/Stable/A-2	4
Northern States Power Wisconsin	BBB+/Stable /A-2	5
Kentucky Utilities Co.	BBB+/Stable/A-2	5
Louisville Gas & Electric Co.	BBB+/Stable/A-2	5
Allete Inc.	BBB+/Stable/A-2	5
Wisconsin Energy Corp.	BBB+/Stable/A-2	5
PSI Energy Inc.	BBB+/Stable/A-2	5
Union Light Heat & Power Co.	BBB+/Stable/--	5
Hawaiian Electric Co. Inc.	BBB+/Stable/A-2	6
Enogex Inc.	BBB+/Stable/--	6
National Fuel Gas Co.	BBB+/Stable/A-2	7
Energy East Corp.	BBB+/Negative/--A2	3
RGS Energy Group Inc.	BBB+/Negative/--	4
Rochester Gas & Electric Corp.	BBB+/Negative/--	4
Michigan Consolidated Gas Co.	BBB+/Negative/A-2	4
Interstate Power & Light Co.	BBB+/Negative/A-2	5
Public Service Co. of New Hampshire	BBB+/Negative/--	5
Kaneb Pipe Line Operating Partnership L.P.	BBB+/Negative/--	5
Consolidated Natural Gas Co.	BBB+/Negative/A-2	6
Detroit Edison Co.	BBB+/Negative/A-2	6
Questar Market Resources Inc.	BBB+/Negative/--	8
Portland General Electric Co.	BBB+/CW-Neg./A-2	5
Columbia Energy Group	BBB/Stable/--	3
NiSource Inc.	BBB/Stable/--	4
Xcel Energy Inc.	BBB/Stable/A-2	5

U.S. Utility and Power Company Ranking List (cont.)		
Public Service Co. of Colorado	BBB/Stable /A-2	5
Northern States Power Co.	BBB/Stable /A-2	5
Southwestern Public Service Co.	BBB/Stable /A-2	5
Appalachian Power Co.	BBB/Stable/--	5
Kentucky Power Co.	BBB/Stable/--	5
Public Service Co. of Oklahoma	BBB/Stable/--	5
Southwestern Electric Power Co.	BBB/Stable/--	5
Northern Indiana Public Service Co.	BBB/Stable/--	5
Entergy Arkansas Inc.	BBB/Stable/--	5
Entergy Louisiana Inc.	BBB/Stable/--	5
Progress Energy Florida	BBB/Stable/--	5
Progress Energy Carolinas Inc.	BBB/Stable/A-2	5
Kansas City Power & Light Co.	BBB/Stable/A-2	6
PNM Resources Inc.	BBB/Stable/--	6
Southern California Edison Co.	BBB/Stable/A-2	6
Empire District Electric Co.	BBB/Stable/A-2	6
Entergy Mississippi Inc.	BBB/Stable/--	6
Entergy New Orleans Inc.	BBB/Stable/--	6
Duke Energy Field Services LLC	BBB/Stable/A-2	6
Arizona Public Service Co.	BBB/Negative/A-2	5
TXU U.S. Holdings Co.	BBB/Negative/--	5
Pinnacle West Capital Corp.	BBB/Negative/A-2	6
Cleco Power LLC	BBB/Negative/A-3	6
Puget Sound Energy Inc.	BBB-/Positive/A-3	5
Puget Energy Inc.	BBB-/Positive/--	5
Green Mountain Power Corp.	BBB-/Stable/--	5
Public Service Co. of New Mexico	BBB-/Stable/A-2	6
Pacific Gas & Electric Co.	BBB-/Stable/ --	6
Cleveland Electric Illuminating Co.	BBB-/Stable/--	6
Ohio Edison Co.	BBB-/Stable/--	6
Toledo Edison Co.	BBB-/Stable/--	6
Pennsylvania Power Co.	BBB-/Stable/--	6
El Paso Electric Co.	BBB-/Stable/--	6
Central Vermont Public Service Corp.	BBB-/Stable/--	6
Entergy Gulf States Inc.	BBB-/Stable/--	6
System Energy Resources Inc.	BBB-/Stable/--	7
Tampa Electric Co.	BBB-/Negative/A-3	4
Black Hills Power Inc.	BBB-/Negative/--	6
Westar Energy Inc.	BB+/Positive/--	5
Kansas Gas & Electric Co.	BB+/Positive/--	6
Indianapolis Power & Light Co.	BB+/Stable/--	4
IPALCO Enterprises Inc.	BB+/Stable/--	4
Enterprise Products Operating L.P.	BB+/Stable/--	6

U.S. Utility and Power Company Ranking List (cont.)		
Enterprise Products Partners L.P.	BB+/Stable/--	6
GulfTerra Energy Partners L.P.	BB+/CW-Neg/--	6
Consumers Energy Co.	BB/Negative/--	6
Tucson Electric Power Co.	BB/CW-Neg/--	6
Dayton Power & Light Co.	BB-/CW-Neg/ -	7
Monongahela Power Co.	B/Stable/--	5
Nevada Power Co.	B+/Negative/--	7
Sierra Pacific Power Co.	B+/Negative/--	7
Sierra Pacific Resources	B+/Negative/--	7
4. Diversified Energy and Diversified Non-Energy		
WPS Resources Corp.	A/Stable/A-1	5
KeySpan Corp.	A/Negative/A-1	4
FPL Group Inc.	A/Negative/--	6
Peoples Energy Corp.	A-/Stable/A-2	5
Vectren Corp.	A-/Negative/--	4
PacifiCorp Holdings Inc.	A-/Negative/--	5
Exelon Corp.	A-/Negative/A-2	7
MDU Resources Group Inc.	A-/Negative/A-2	7
Centennial Energy Holdings Inc.	A-/Negative/A-2	8
Otter Tail Corp.	A-/Negative/--	8
Kinder Morgan Energy Partners L.P.	BBB+/Stable/A-2	4
Northeast Utilities	BBB+/Stable/--	5
OGE Energy Corp.	BBB+/Stable/A-2	6
LG&E Energy Corp.	BBB+/Stable/--	6
Cinergy Corp.	BBB+/Stable/A-2	6
Constellation Energy Group Inc.	BBB+/Stable/A-2	7
Sempra Energy	BBB+/Stable/A-2	7
Pepco Holdings Inc.	BBB+/Negative/A-2	5
Conectiv	BBB+/Negative/--	5
Alliant Energy Corp.	BBB+/Negative/A-2	6
DTE Energy Co.	BBB+/Negative/A-2	6
Dominion Resources Inc.	BBB+/Negative/A-2	7
Kinder Morgan Inc.	BBB/Stable/A-2	5
American Electric Power Co. Inc.	BBB/Stable/A-2	6
Entergy Corp.	BBB/Stable/--	6
Hawaiian Electric Industries Inc.	BBB/Stable/A-2	6
Progress Energy Inc.	BBB/Stable/A-2	6
PPL Corp.	BBB/Stable/--	7
Public Service Enterprise Group Inc.	BBB/Stable/A-2	7
Great Plains Energy Inc.	BBB/Stable/--	7
Duke Energy Corp.	BBB/Stable/A-2	7
Duke Capital Corp.	BBB/Stable/A-2	8

U.S. Utility and Power Company Ranking List (cont.)		
TXU Corp.	BBB/Negative/--	5
Centerpoint Energy Inc.	BBB/Negative/--	5
Cleco Corp.	BBB/Negative/A-3	6
Potomac Capital Investment Corp.	BBB/Negative/--	8
MidAmerican Energy Holdings Co.	BBB-/Positive/--	5
FirstEnergy Corp.	BBB-/Stable/--	6
TECO Energy Inc.	BBB-/Negative/A-3	5
Black Hills Corp.	BBB-/Negative/--	8
Avista Corp.	BB+/Stable/--	6
Edison International	BB+/Stable/--	6
TNP Enterprises	BB+/Stable/--	6
New York Water Service Corp.	BB/Stable	7
CMS Energy Corp.	BB/Negative/--	7
DPL Inc.	BB- /CW-Neg/--	8
Williams Companies Inc. (The)	B+/Negative/--	8
Allegheny Energy Inc.	B/Stable/--	7
Dynegy Inc.	B/Negative/--	8
Dynegy Holdings Inc.	B/Negative/--	9
El Paso CGP Corp.	B-/Negative/--	6
Aquila Inc.	B-/Negative/--	8
El Paso Corp.	B-/Negative/--	8
5. Energy Merchants/Power Developers/Trading and Marketing		
Entergy-Koch L.P.	A/Stable/--	9
KeySpan Generation LLC	A/Negative/--	5
FPL Group Capital	A/Negative/A-1	8
Exelon Generation Co.	A-/Negative/A-2	8
AmerenEnergy Generating Co.	A-/CW-Neg/--	8
Southern Power Co.	BBB+/Stable/--	6
LG&E Capital Corp.	BBB+/Stable/A-2	9
Alliant Energy Resources Inc.	BBB+/Negative/--	9
American Ref-Fuel Co. LLC	BBB/Stable/--	6
PSEG Power LLC	BBB/Stable/--	8
PPL Energy Supply LLC	BBB/Stable/--	8
TXU Energy Co. LLC	BBB/Negative/--	7
Duke Energy Trading and Marketing LLC	BBB-/Negative/--	10
Northeast Generation Company	BB+/Negative/--	9
Cogentrix Energy	BB-/Stable/--	6
PSEG Energy Holdings Inc.	BB-/Stable/--	9
AES Corp.	B+/Stable/--	9
NRG Energy Inc.	B+/Stable	9
Allegheny Energy Supply Co. LLC	B/Stable/--	8
Reliant Resources Inc.	B/Negative/--	8

U.S. Utility and Power Company Ranking List (cont.)		
Calpine Corp	B/Negative/--	9
Edison Mission Energy	B/Negative/--	9
Orion Power Holdings Inc	B/Negative/--	9
Reliant Energy Mid-Atlantic Power Holdings LLC	B/Negative/--	9
Mirant Americas Generation Inc.	D/--/--	10
Mirant Americas Energy Marketing L.P.	D/--/--	10
Mirant Corp.	D/--/--	10
NEGT Energy Trading Holdings Corp	D/--/--	10
PG&E National Energy Group	D/--/--	10
USGen New England Inc.	D/--/--	10

APS-15

RESEARCH

Pinnacle West Capital Corp.

Publication date: 16-Dec-2005
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EXHIBIT
APS-15
ADMITTED

Corporate Credit Rating	
	BBB/Stable/A-2
Outstanding Rating(s)	
Pinnacle West Capital Corp.	
Sr unsecd debt	
Local currency	BBB-
CP	
Local currency	A-2
Arizona Public Service Co.	
Corporate Credit Rating	BBB/Stable/A-2
Sr unsecd debt	
Local currency	BBB
CP	
Local currency	A-2
PVNGS II Funding Corp. Inc.	
Corporate Credit Rating	BBB/Stable/--
Sr unsecd debt	
Local currency	BBB
Corporate Credit Rating History	
Sept. 28, 2000	BBB
Feb. 28, 2002	BBB/A-2

Major Rating Factors

Strengths:

- A renewed corporate focus on the regulated operations of Arizona Public Service Co. (APS), which continues to enjoy retail electric sales growth that is among the highest in the U.S., creating opportunities for strong earnings;
- Pinnacle West Energy Corp.'s (PWEC) exit from the merchant generation business, which should be completed by the end of 2005;
- An accelerated asset sales program through 2005 at SunCor, Pinnacle West Capital Corp.'s (PWCC) real estate investment arm, which ends in 2005 and is generating annual dividends to PWCC in the $80 million-$100 million range;
- The conclusion of APS' protracted 2003 general rate case, which reached settlement in 2004 and was approved by the Arizona Corporation Commission (ACC) in spring 2005 and favorably resolved several key issues.

Weaknesses:

- A consolidated financial profile that has been weakening since 2003 due largely to regulatory lag associated with the review and disposition of APS rate proceedings, which has resulted in retail base rates being set at levels that are insufficient to recover current costs;
- Rising APS cost deferrals resulting from higher natural gas prices and purchased power costs that were $147 million as of Sept. 30, 2005 and Standard & Poor's expectation that these balances will at least double in 2006;
- Operational problems at the Palo Verde nuclear units, which supply about one-third of APS' generation;

- Utility capital expenditures that are expected to increase to nearly $2 billion from 2005 through 2007, against historic spending of $1.4 billion from 2002 through 2004;
- The expectation that while SunCor's operations will shed legacy holdings, consolidated operations will continue to invest in real estate development, albeit under a business model that does not rely on parental support.

Rationale

The consolidated credit rating of PWCC reflects a satisfactory business profile of '5' (on a 10-point scale where '10' is the weakest) that reflects the company's progress in exiting diversified business interests that it began pursuing in the late 1990s. PWCC's principal subsidiary is APS, which provides retail electric service to around a million customers within its service territory, which spans roughly two-thirds of Arizona and includes about half of the Phoenix metropolitan statistical area (MSA). In fiscal 2004, APS contributed about 76% of consolidated operating cash flows. In addition to retail sales, APS also operates a trading and marketing company, APS Power Marketing (APS PM), which is focused primarily on economic purchases and sales, and engages in minimal speculative trading. Trading and marketing contributed 2% of consolidated cash flows in 2004.

PWCC also owns four other subsidiaries, PWEC, SunCor, El Dorado Investment Co., and APS Energy Services, which collectively contributed about 12% of consolidated cash flows. The company has been focused on reducing many of these operations, most notably the merchant assets of PWEC that have generally been unprofitable in a southwest power market that has high reserve margins. Beginning in 2001, the merchant generation subsidiary brought online about 2,200 MW, consisting of five combined cycle plants in Arizona and one near Las Vegas, Nev. In July 2005, PWEC transferred the Arizona facilities (about 1,790 MW) to APS, as part of a settlement the utility reached in conjunction with its 2003 general rate case. In August 2005, PWCC announced plans to sell its remaining 75% interest in its 570 MW Nevada plant, Silverhawk, to Nevada Power (B+/Positive/NR) for $208 million. If regulators approve the sale, the transaction should be completed by the end of 2005, marking the complete wind down of PWEC's operations. PWEC took a write-off of about $55 million (after-tax) for the sale.

SunCor develops residential, commercial, and industrial real estate projects in Arizona, Idaho, New Mexico, and Utah. The real estate subsidiary is in the last year of a three-year accelerated sale program to shed some $180 million of holdings, most of which were acquired in the 1980s. The asset sales are resulting in additional annual dividends to the parent. SunCor will continue to pursue real estate projects, but to reduce initial capital requirements when developing building sites, it is increasingly partnering with landowners to share investment in infrastructure. SunCor is expected to be self-supporting going forward, and all debt, which stood at about $66 million as of Sept. 30, 2005, will be non-recourse to PWCC. Once the asset sales program is complete this year, the company is expected to account for between 13% and 16% of per share earnings in 2006 and 2007, but, on a cash flow basis, is expected to be significantly less.

Other interests held by PWCC are negligible. El Dorado Investment Co., PWCC's venture capital investment arm, has pared its interests. El Dorado sold its principal holding, NAC, a nuclear dry cask storage consulting firm, in November 2004. PWCC also owns APS Energy Services, a competitive retail energy supplier that provided about 2% of operating cash flows in 2004.

The back-to-basics model that PWCC is now pursuing implies that consolidated performance will be increasingly tied to the vertically integrated utility operations of APS. Throughout Arizona, a strong influx of new residents and an unprecedented housing boom continues. As a result, energy sales and peak load growth are growing at about 4% per annum, roughly twice the national average growth rate for investor-owned utilities and second only to Nevada Power, which serves the Las Vegas area.

Balancing these strong prospects for growth is a regulatory environment that has been slow to reflect current costs in retail rates and appears to be struggling with passing through to retail ratepayers the costs of recent and significant increases in natural gas. Regulatory lag is increasingly pressuring APS' financials, and has led to large power and fuel cost deferrals of $147 million as of Sept. 30, 2005. Standard & Poor's Ratings services has developed its own estimates based on publicly available information that suggest 2006 deferrals will be near $300 million, but could be higher depending on factors that include how the ACC treats the company's surcharge filing, discussed further below.

This large deferred balance is occurring despite APS's completion in March 2005 of a major rate case, in which retail rates increased by on average 4.21% beginning April 1. The settlement negotiated with this case also allowed the company to implement a power supply adjuster (PSA). The PSA defers for future recovery 90% of the difference between the fuel, purchased power and associated hedging costs and those reflected in retail rates.

But the most recently completed rate case has provided only modest financial support for the company; more of a concern is that, by design, aspects of the PSA make it a weak tool for fuel and purchased power cost recovery. For example, the adjuster may only reset annually in April, is capped at a 4 mill per kilowatt-hour (kWh) limit over its life, and the company may not collect more than $776 million in annual fuel and purchased power costs. Current retail electric rates charged by APS are based on 2003 fuel costs, when the average price of natural gas paid by the utility averaged about $5.50/million BTU (mmBTU) and constituted about 25% of its retail resource portfolio. For the first nine months of 2005, owned gas generation provided 28% of retail requirements, and power purchases that are predominately from gas-fired resources constituted approximately 10% of the supply portfolio.

The need to update retail rates to reflect current costs prompted the company to file a second rate case last month, less than eight months after its last case was approved. APS is requesting a $409.1 million, or 19.9%, increase in its annual retail electricity revenues. The filing is based on a historical test year ended Dec. 31, 2004, adjusted for known and measurable changes. About 12% of the requested increase is related to fuel and purchased power costs. The company's request is likely to be revised slightly as a result of an ACC staff request in December that the company revise its application to be based on the 12 months ending Sept. 30, 2005, rather than the year-end 2004 numbers in the original application. APS will file the updated information by Jan. 31, 2006, and a procedural schedule should follow. The company expects an outcome by the end of 2006. Recent statements by the ACC suggest it could be spring 2007 before a ruling is seen. APS' last rate case took 23 months to process.

In the interim, the ACC may grant APS rate relief in the form of a surcharge approval and an April adjustment to the PSA. Under the terms of the settlement, APS must file a plan of recovery of fuel and purchased power costs if its deferred balances exceed $100 million. In July, the company filed an application seeking recovery of $100 million, which it later lowered to $80 million as a result of concerns expressed by ACC staff and ratepayer advocates that about $20 million was associated with outages at Palo Verde. The company requests the $80 million be collected over two years, which would increase retail rates by about 1.7%. The application is pending before the ACC.

APS will also seek recovery of additional deferred costs as an adjustment to its PSA, which may be made annually beginning in April 2006. The utility is able to request that the adjuster be increased up to the maximum permitted under the settlement or $0.004 per kWh. This adjustment is in addition to the surcharge request.

Short-term credit factors

PWCC's short-term rating is 'A-2'. The rating is supported by the preponderance of cash flows being produced by APS, a vertically integrated electric utility. Because of APS' sizable CP program, near-term liquidity should be adequate to support cash outlays for power and fuel not recoverable in rates. And because APS is heading into its shoulder season, when demand for electricity for space cooling drops significantly, the build-up of its power cost deferrals should slow. APS has hedged most of its power and gas purchases remaining in 2005, 85% of 2006 requirements, and about 65% for 2007.

Consolidated cash and investments stood at more than $900 million as of Sept. 30, 2005. However, $500 million was used on Oct. 3, 2005 to call Pinnacle West Energy's floating-rate notes that were due April 2007. Also impacting the cash and invested position is the increased amount of collateral held under bilateral contracts.

Both PWCC and APS maintain CP programs. Neither program had any CP balances as of Sept. 30, 2005. PWCC's program is for $250 million and is supported by a five-year, $300 million credit facility that expires in December 2010. The revolver allows PWCC to use up to $100 million of the facility for letters of credit. The revolver has no material adverse change clauses.

APS' short-term rating is also 'A-2'. The rating is supported by the stability of cash flows from regulated operations and good liquidity, although APS will need to continue to rely on borrowings to fund portions of its capital expenditure program, which is expected to be about $800 million in 2005 (and includes $190 million for the purchase of the Sundance power plant), up significantly from $484 million in 2004. APS maintains a $250 million CP program. APS has a five-year, $400 million revolver that expires in December 2010 that supports the utility's CP program, and also provides an additional $150 million for other liquidity needs, including $100 million for letters of credit. The supporting facility has no material adverse change clauses. Consolidated maturities are modest and consist of $384 million in 2006, of which $300 million is a note at the parent, which is due in April. Currently, there are no obligations due in 2007, as PWEC called at par in early October some $500 million in notes that it issued in April 2005 to retire an inter-company loan between PWEC and APS that was associated with the PWEC assets now owned by APS.

Outlook

The stable outlook reflects Standard & Poor's expectation that the ACC will resolve APS' large deferred power costs through a surcharge ruling no later than year-end 2005 that supports timely recovery of APS' $80 million request. In addition, the outlook presumes that over time consolidated financial results will reflect modest improvements in credit metrics, and that the Palo Verde units will return to their typically strong capacity factors. Any related adverse development will result in a negative outlook or a rating action. No positive rating changes are expected in the short term.

Ratings Methodology

The 'BBB' corporate credit rating of PWCC reflects the consolidated creditworthiness of the parent, its principal subsidiary, APS, and PWCC's other four subsidiaries, which, due to their size, are not significant ratings drivers at this time. The unsecured notes of PWCC are rated 'BBB-', one notch below its corporate credit rating, reflecting the structural subordination of this debt to the substantial amount of debt issued by APS. In April 2004, APS retired all first mortgage bonds and utility debt currently consists of senior unsecured obligations, which are rated the same as the consolidated corporate credit rating.

Regulation

APS is regulated by the ACC, which consists of five popularly elected commissioners that serve four-year, staggered terms. APS is also regulated by the FERC, which has jurisdiction over transmission and wholesale power sales. All other PWCC subsidiaries are not subject to regulatory oversight.

The regulatory climate in Arizona has generally been modestly supportive of credit quality, but challenges have been increasing lately. As in many other states, policy makers are trying to balance the need to pass along to customers significant increases in power and fuel costs against concerns that such efforts will introduce rate shock.

In spring 2005, APS completed a nearly 24-month general rate case, its first since 1991. The case, filed in 2003, sought an additional $175 million in rates, or about a 9.8% retail rate hike. As part of a negotiated settlement with parties, the utility was awarded a 4.21% increase, which the ACC approved in March 2005. The size of the increase was tepid, given APS' rising fuel costs and expectations for growing capital expenditures. As a result, the current rate case is necessitating much higher increases. In addition to the rate relief of nearly 20%, the company is also seeking a stronger PSA mechanism. Specifically, the utility has asked the ACC to lift the current restriction on its PSA to have a lifetime cap that does not allow total adjustments to exceed $0.004 per kWh. Importantly, APS' current settlement approved by the ACC caps total fuel and purchased power costs at $776 million. The company estimates these costs could be $834 million by the fourth quarter of 2006. Thus, APS has requested a waiver of this provision of the settlement. Timing issues may arise, given that the rate case is not expected to be completed before the utility hits the cap.

APS is a member of WestConnect, which is a collection of southwest utilities assessing the benefits of forming a regional transmission organization (RTO). In 2004, FERC withdrew its Notice Of Proposed Rulemaking (NOPR) for Locational Marginal Pricing and relaxed its position on mandatory RTOs, deferring to regional needs. This, coupled with a projected startup cost for an RTO of $160 million and on-going annual cost in excess of $50 million, resulted in the participants of WestConnect to modify original expectations that the entity would become a formal RTO. Instead, the participants have agreed to work collaboratively to assess stakeholder and market needs and have made several improvements since signing a December 2004 memorandum of understanding (MOU), including developing a common OASIS (Open Access Sametime Information System) site for transmission services. Since going operational, the common OASIS has expanded to include most of the transmission providers in the western interconnection.

Markets

The strength of the Phoenix metropolitan market is an important credit attribute for PWCC. The Phoenix market is reflective of a diverse customer base, electric revenues that are not overly dependent on key customer accounts, and very substantial growth that is not expected to appreciably decrease over the next five years.

Phoenix is the sixth-largest city in the U.S., and the underlying economy served by APS has experienced remarkable growth in jobs and in-migration over the past decade. Approximately 63% of Arizona's population resides in the Phoenix-Mesa MSA. Since 2001, annual population growth of the state has been nearly 3% in most years, with 2005 expected to be about 3.2%. This contrasts with U.S. population growth of about 1%. APS' economic base is diversified across sectors, with the largest concentrations in professional and business services (16%), government (13%), retail trade (12%) education and health services (10%), and leisure and hospitality services (10%), while manufacturing, construction, and financial activities each account for about 8%.

A strong and growing economy has fuelled significant utility growth. Growth in retail sales has ranged from 4% to 5% between 2002 and 2004, with 2005 sales expected to be 5.5% above 2004 levels (weather normalized). The utility is adding about 37,000 new accounts per year, and from 1999 to 2004, average annual customers growth was 3.7%. Peak load growth going forward is also expected to increase by around 4% per year. Even so, forecasts predict this very robust growth to continue to significantly exceed national averages.

APS' customer load reflects diversity across residential, commercial, and industrial segments. In 2004 residential customers accounted for 50% of APS' retail electric sales. Commercial and industrial accounts respectively totaled 42% and just 7%. This large portion of residential accounts is a credit strength, as these customers are the least likely segment to leave the utility in the event that retail competition is invigorated (see "Competition," below). Moreover, APS industrial sales lack significant customer concentration. In 2004 only one end user accounted for greater than 1% of APS' retail electric revenues (at about 1.2%) and the top 10 customers accounted for just 2.9%. Sales are also spread across a varied economic base of industries, which should ensure that APS' revenues are insulated from any sharp contractions in particular segments of the economy. However, one of APS' most important customers is a copper mine, and while, as a primary industry, demand for copper is currently strong, its usage of electricity is expected to be highly cyclical.

Long-term growth prospects for Phoenix remain strong, with employment in the MSA currently expanding at twice the national average; the strongest gains are in construction and education and health services, followed closely by the leisure and hospitality industries.

Competition

As of Jan. 1, 2003, all APS retail customers became eligible to choose an alternate energy supplier. No competitive electric suppliers currently offer service as an alternative to APS. Similarly, retail suppliers do not appear to be active in other Arizona major electric markets served by the Salt River Project and Tucson Electric Power. Legal challenges and regulatory inquiries into the benefits of retail competition have created uncertainty about the future and pace of retail electric competition.

As shown in Table 1, relative to comparable utilities serving the west and southwest markets, APS rates are about average.

Table 1 Retail Rates For Selected Southwest Electric Utilities

Company Name	Residential $/MWh	Commercial $/MWh	Industrial $/MWh	Total $/MWh
As of June 30, 2005				
PacifiCorp (Utah Only)	72.2	57.74	39.17	54.79
Public Service Co. of New Mexico	82.46	72.41	48.14	71.74
Salt River Project	82.77	68.17	46.12	71.98
Arizona Public Service Co.	87.09	75.54	61.44	79.21
Tucson Electric Power Co	89.59	100	64.59	82.5
Nevada Power Co.	99.44	93.02	72.84	87.69
Sierra Pacific Power Co.	115.54	105.06	78.32	95.74
El Paso Electric Co.	115.63	99.14	64.38	97.67
Note: MWh--megawatt-hour.				

The near-term risk of retail competition for APS is low due to the lack of alternate suppliers offering competitive services, not only in APS' territory but also in Arizona generally. The reasons behind the absence of alternative electric suppliers are complex but generally stem from the difficult time retailers have had competing against utilities that have been required to institute rate decreases as part of restructuring begun in 2000 and 2001. Other contributing factors include the requirements placed on suppliers to provide revenue cycle services for their loads.

Moreover, APS' heavy concentration of smaller volume customers provides a measure of permanent insulation from retail competition in the unlikely event that regulators decide to modify the market rules to make them more hospitable to competitive suppliers. For these reasons, Standard & Poor's believes that the threat of retail competition is currently low. But given that APS retail rates are somewhat higher than average relative to comparable utilities, market reforms, if introduced, could encourage some load migration to competitive retailers.

Operations

APS' operational profile is characterized by a predominately coal and nuclear-based system that will have growing exposure to natural gas over the next five years. Due to APS' rate settlement, the utility is prohibited from building its own generation for 10 years, unless it can demonstrate that supply bids are economically unattractive or insufficient to meet requirements. Much of the utility's new supplies are expected to be gas-fired.

Based on 2005 summer capacity, APS owns or jointly participates in the shared ownership of about 6,021 MW of capacity: 1,725 MW of coal through its participation in the Cholla, Four Corners, and Najavo plants; 1,110 MW of nuclear via its joint ownership in the three units that compose the Palo Verde Nuclear Station; approximately 1,125 MW of gas- and oil-fired combustion turbines, 2,061 MW of newly acquired Arizona gas plants from PWEC, and the 325 MW Sundance plant. It has about another 840 MW in long-term purchase and exchange agreements, and makes about 900 MW of market purchases, for a total resource portfolio in 2005 of about 7,766 MW, which provides about a 13% reserve margin against its 2005 peak of 7,000 MW.

With the rate-basing of the Arizona PWEC assets, APS is roughly in resource balance for 2005, but thereafter must add significant amounts of generation each year, requiring, for example, more than 1,000 MW per year beginning in 2007 due to service territory growth. Under APS' settlement, the company is restricted from building its own generation to meet retail loads until 2015 and is using an RFP process to procure needed supplies. However, there are provisions for relaxing this rule if the utility receives uneconomic or insufficient bids.

A substantial portion of APS' energy is provided by Palo Verde, which typically supplies about 25%-30% of the utility's energy requirements. Palo Verde is the largest producer of electricity in the country, producing more than 30 billion kWh of electricity every year. APS owns 29.1% of the approximately 4,000 MW, three-unit facility and operates the plants.

The nuclear facility has been beset by a series of operational problems in 2005, which have affected plant performance and necessitated replacement power purchases during this preceding spring and summer. For the nine months ending Sept. 30, 2005, Palo Verde's capacity factor was 83% in contrast to 94% in 2002 and 87% in 2003. (The lower factor in 2003 can largely be explained by the planned outage at unit 2 to replace the two steam generators, which required a 75-day outage to install, as compared to the typical 33-day refueling.) In 2004 and 2005, however, unexpected outages have dragged on performance. In 2004, plant capacity factors dipped under 86%, a six-year low. In June 2004, all three units were offline for one week--the first time since their online dates in the 1980s--following a grid disturbance. Transmission problems caused the units to properly shut down, but because a diesel backup unit did not automatically start, the units were offline a week for inspection.

Calendar 2005 capacity factors are also expected to be at or below 2004 averages, due to both planned and unplanned outages. Earlier this year, problems with the heating elements in unit 3 resulted in the extension of a planned 10-day outage to 32 days. The company is in the process of replacing unit 1's steam generators, as part of an extended refueling outage, which began in early October and is expected to be completed by the end of December (Unit 3's replacements will occur in the fall of 2007).

The Nuclear Regulatory Commission (NRC) has faulted the company on two related safety issues. In July 2004, the company identified piping in a portion of the emergency cool system that was dry. The pipe is designed to be kept wet and as a result the NRC flagged the situation as "yellow," the second-most serious of four categories of violations. The company has paid a $50,000 fine associated with the issue.

In September 2004, the NRC identified an issue with the company's emergency planning. Specifically, APS made a change in its emergency preparedness documents, which is allowed under its license so long as the NRC believes the change does not result in weakening safety standards. The NRC held a hearing in June 2005 and concluded that the company had committed a Level 3 violation (on a scale of '1' to '5' with '5' being the least concerning) but it waived the fines associated with the event because it was satisfied with the company's corrective actions.

The yellow flag triggered onsite NRC inspections in October. On October 11, 2005, units 2 and 3 were taken offline after NRC officials at the site raised concerns that the unit's emergency cooling systems might not operate as designed under a range of hypothetical scenarios. The plants were brought back into service 10 days later after the company successfully demonstrated via modeling exercises that the cooling systems would operate as designed

Financial Policy

PWCC's financial strategy is moderate. Its divestiture of substantial non-regulated activities, particularly merchant operations, has limited PWCC's exposure to volatile revenue streams that could weaken financial performance. PWCC's April 2005 issuance of $250 million in common stock has increased adjusted consolidated equity. However, borrowing requirements could rise in 2006 to fund additional power and fuel costs deferrals and to invest in capital expenditures. The company increased its dividend 5.3% in 2005.

Financial Profile

Accounting

PWCC's financial statements are audited by Deloitte and Touche LLC, which provided an unqualified opinion for fiscal 2004. The company may update its published financial results from prior years as required by accounting standards. These updates can give rise to modest revisions of prior year results. Standard & Poor's utilizes the most up-to-date results published by the company for years prior. For this reason, there may be small changes in the metrics it publishes for a particular year in subsequent years.

Standard & Poor's makes several adjustments to PWCC's financial statements. In 1986, APS sold about 42% of Palo Verde Unit 2 as part of a sale-leaseback transaction. Standard & Poor's treats these obligations as operating leases and computes an off balance sheet obligation of $524 million in 2004. The lease expires in 2015. The company has a modest level of power purchased obligations, which generates an off-balance-sheet adjustment of about $45 million.

In the third quarter of 2005, PWCC realized significant proceeds from real estate sales. In the past, Standard & Poor's has accounted for real estate cash flows as presented by the company in which cash inflows and outflows from SunCor commercial sales are presented as a component of cash flows from investing activities. However, cash inflows and outflows related to SunCor residential projects are presented net basis within cash flows from operating activities. To recognize about $82 million in proceeds from commercial real estate investments, Standard & Poor's has included this amount in operating cash flows. At the same time, Standard & Poor's has removed from operating cash flows changes in trading assets and liabilities that constitute margin account inflows to the company.

Profitability and cash flow

In 2004, PWCC's consolidated cash coverage ratios were weak for the rating category, largely reflecting the need for rate relief at APS, which did not occur until the beginning of the second quarter in 2005. Fiscal 2004 adjusted funds from operations (FFO) to interest coverage was 3.3x, while adjusted FFO to total debt was 14.5%.

Expectations for 2005 were that consolidated financial performance would improve due to good sales growth at APS, stable operational performance, the modest rate increase authorized, and an ability to rely on the PSA and surcharge process to recoup costs. However, much higher than anticipated natural gas prices have led to deferrals that exceed amounts currently considered for recovery by the ACC under the current surcharge proceedings and are expected to pull down 2005 results. In addition, power costs have increased reflecting the need to make purchases to replace Palo Verde unit capacity, which has suffered from several unplanned outages this year. For the 12 months ending Sept. 30, 2005, adjusted FFO interest coverage was 3.3x and adjusted FFO to total debt was 14.6%, which includes $82 million in real estate proceeds categorized under investing activities and excludes cash inflows associated with collateral paid by counterparties to APS and PWCC. Without the addition to account for the real estate proceeds, adjusted FFO to interest coverage is 3.0x and adjusted FFO to debt is 12.7%. Given the winding down in 2005 of SunCor's sale of "legacy" holdings, contributions to operational cash flows by SunCor are expected to decline.

In 2006, these pressures are expected to continue, and financial performance will be heavily predicated on near-term regulatory rulings addressing these issues. Even if the company is granted full recovery of its $80 million surcharge request and its PSA is permitted to be adjusted upward by the full 4 mills/ kWh, Standard & Poor's estimates are that deferrals will nevertheless be near the $300 million mark by year end. While lower natural gas prices, which have led to the bulk of APS' deferrals, could relieve some of the utility's cost pressures, given that about 75% of its fuel portfolio is hedged, substantial changes in the company's forecast costs are not expected.

Capital structure and financial flexibility

PWCC's capital structure is more robust than its coverage ratios, with debt to total capital at 53.1% as of Sept. 30, 2005. Consolidated capital expenditures are expected to be $928 million in 2005, of which APS is expected to account for $802 million. SunCor expenditures are expected to total $114 million. In company forecasts provided to Standard & Poor's, SunCor capital expenditures are excluded because the real estate company's cash flows support its capital investments and PWCC has pledged that it does not expect to provide capital to these operations.

PWCC recently received permission to infuse equity in excess of $100 million in 2005. Specifically, PWCC expects to infuse the remaining $150 million of the proceeds from its issuance of common stock as well as the approximately $210 million in net proceeds from the pending sale of Silverhawk into the utility. In November 2005, the ACC approved the additional equity infusion.

Table 2 Pinnacle West Capital Corp.--Peer Comparison				
Industry Sector: Regulated T&D - Electric				
	--Average of past three fiscal years--			
	Pinnacle West Capital Corp	**Xcel Energy Inc.**	**PNM Resources Inc.**	**UniSource Energy Corp***
Rating	BBB/Stable/A-2	BBB/Stable/A-2	BBB/Stable/A-2	BB/Negative/B-2
(Mil. $)				
Sales	2,688.2	8,602.4	1,409.8	991.9
Net income from cont. oper.	211.1	(393.7)	70.0	41.4
FFO	733.4	1,254.7	247.5	220.9
Capital expenditures	720.3	1,495.0	184.9	138.0
Cash and equivalents	124.0	501.4	11.2	115.4
Total debt	3,311.0	10,036.3	1,108.6	1,849.9
Preferred stock	0.0	105.1	12.4	0.0
Common equity	2,822.0	5,011.5	1,050.3	519.5
Total capital	6,133.1	15,165.6	2,175.2	2,369.4
Ratios				
Adj. EBIT interest coverage (x)	2.4	1.8	2.4	1.4
Adj. FFO interest coverage (x)	4.1	2.6	4.0	2.4
Adj. FFO/avg. total debt (%)	19.8	10.5	18.5	11.9
Net cash flow/capital expenditures (%)	83.0	58.6	111.9	142.1
Adj. total debt/capital (%)	58.0	68.4	57.2	78.2
Return on common equity (%)	6.4	(8.9)	6.4	8.2
Common dividend payout (%)	73.0	(93.5)	52.0	47.4
N.M.-Not Meaningful.				
*Rating shown reflects Tucson Electric Power Co.; holding Company not rated.				

Table 3 Pinnacle West Capital Corp.--Financial Summary					
Industry Sector: Regulated T&D - Electric					
	--Fiscal year ended Dec. 31--				
	2004	2003	2002	2001	2000
Rating history	BBB/Negative/A-2	BBB/Stable/A-2	BBB+/Stable/A-2	BBB+/Stable/A-2	BBB+/Stable/A-2
(Mil. $)					
Sales	2,899.7	2,759.5	2,405.3	2,634.8	3,119.5
Net income from cont. oper.	243.2	240.6	149.4	312.2	302.3
FFO	525.8	890.4	783.9	505.9	690.9
Capital expenditures	538.2	713.3	909.3	1,055.6	658.6
Cash and equivalents	163.4	131.1	77.6	28.6	10.4
Total debt	3,273.2	3,407.6	3,252.3	3,205.0	2,501.4
Preferred stock	0.0	0.0	0.0	0.0	0.0
Common equity	2,950.2	2,829.8	2,686.2	2,499.3	2,382.7
Total capital	6,223.4	6,237.4	5,938.5	5,704.3	4,884.1

Ratios					
Adj. EBIT interest coverage (x)	2.5	2.2	2.5	3.2	3.2
Adj. FFO interest coverage (x)	3.3	4.6	4.4	3.2	4.1
Adj. FFO/avg. total debt (%)	14.5	23.6	21.1	15.1	22.9
Adj. net cash flow/capital expenditures (%)	68.1	108.1	73.3	38.4	82.2
Adj. total debt/capital (%)	56.6	58.4	59.1	60.8	57.3
Return on common equity (%)	7.7	7.1	4.1	10.8	12.2
Common dividend payout (%)	68.6	65.4	92.2	41.4	39.9

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December 21, 2005

Research Update: Pinnacle West Capital's, Arizona Public Service's Ratings Lowered To 'BBB-'; Outlook Stable

Primary Credit Analyst:
Anne Selting, San Francisco (1) 415-371-5009;anne_selting@standardandpoors.com

Table Of Contents

Research Update: Pinnacle West Capital's, Arizona Public Service's Ratings Lowered To 'BBB-'; Outlook Stable

Credit Rating: BBB-/Stable/A-3

Rationale

On Dec. 21, 2005, Standard & Poor's Ratings Services lowered its corporate credit ratings on Pinnacle West Capital Corp. (PWCC) and principal electric utility subsidiary Arizona Public Service Co. (APS) to 'BBB-' from 'BBB'. The outlook is stable.

This action is based on increased regulatory and operating risk at APS. Specifically, Standard & Poor's is concerned that the Arizona Corporation Commission (ACC) is not expeditiously addressing APS' growing fuel and purchased-power cost deferrals, which have grown much more rapidly than expected in 2005, particularly because of elevated gas prices and the utility's increased dependence on this fuel. In November 2005, APS filed for a nearly 20% increase in customer electric rates, but it appears unlikely that a resolution will be reached until 2007, and may be delayed to mid-2007. Combined with a year of weaker-than-expected performance at the historically reliable Palo Verde nuclear station, Standard & Poor's now views the business profile of PWCC and APS as a satisfactory '6' (on a 10-point scale where '1' is excellent) and no longer a '5'.

APS's fuel and purchased-power cost deferrals were nearly $150 million as of Sept. 30, 2005. Because the ACC has not acted on the utility's request to recover a portion of this amount in a surcharge, this entire balance, and any new additions through Dec. 31 will be carried into 2006. Standard & Poor's estimates that the utility may incur an additional $265 million in deferral balances by year-end 2006. Actual balances will be a function of how the ACC addresses existing amounts, as well as forward market prices and the company's hedged positions. To date, APS has hedged about 85% of its purchased power and natural gas fuel price risk for its retail load in 2006 and 65% in 2007.

A surcharge proceeding that would resolve $80 million of the utility's current deferrals has been before the commission for five months. The surcharge process was mandated by the ACC as part of the settlement of APS's 2003 rate case that it approved in March 2005. APS is required to notify the ACC when its fuel and purchased-power deferrals reach $50 million and to file a plan for recovery before deferrals exceed $100 million. In July 2005, the utility filed an application to recover about $100 million through a two-year surcharge, but reduced it to $80 million to exclude Palo Verde outage related costs, which will be addressed in a later proceeding. If approved, residential rates would increase about 1.6%.

Since the fall of 2005, Standard & Poor's has conditioned a stable outlook on the satisfactory resolution of this portion of deferrals before year-end. Yet, because of the sustained increase in deferrals, even if the surcharge is implemented, it will likely resolve only about one-half of the company's expected deferred balances at year-end 2005.

Beyond the surcharge, additional 2005 deferred balances can be addressed through an adjustment to the company's power supply adjuster (PSA). However, the PSA has several limitations. It allows APS to collect 90% of the difference between actual fuel, purchased power, and associated hedging costs and those reflected in retail rates. But as per the settlement, APS may not be granted an adjustment before April 2006. Until then the PSA is set at zero. This is problematic because retail rates reflect fuel and purchased-power costs based on 2003 costs when the price of natural gas averaged about $5.50 per million BTU. In addition to a certain wait of four months for PSA adjustments to be authorized, upward adjustments are capped at 4 mils per kilowatt-hours for the life of the mechanism. As a result, all or nearly all of the PSA capacity is likely to be absorbed in APS's first PSA filing, and the utility is expected to end the summer of 2006 needing another surcharge to address additional balances that will accumulate. Thus, any rate relief granted for remaining 2005 deferrals will not completely resolve the issue because the onset of the utility's summer cooling season in late April will contribute additional amounts to deferred balances.

APS's new general rate case request totals $409.1 million (19.9%) increase in annual revenues. About $247 million of the request is related to increased fuel and purchased-power costs. Recent public statements by the ACC suggest spring 2007 may be the earliest a decision could be expected. APS's last rate case took nearly 23 months to conclude, and there is therefore substantial uncertainty as to when the case will be completed.

An additional factor contributing to PWCC's weakened business profile is the performance of the Palo Verde nuclear units in 2005. The three-unit facility typically supplies 25% to 30% of the utility's energy requirements. In 2005, the combined capacity factor for the three units is expected to be about 78%, against the company's forecast of 86%. While some of the deterioration reflects the expected increase in Unit 1's refueling outage to 75 days from 33 days, enabling the replacement of the unit's steam turbine generators, the units have been beset by a series of operational problems, which include an overhang of issues first raised by the NRC in 2004. Specifically, in the summer of 2004, the company identified piping in a portion of the emergency cooling system that was dry, a situation that the NRC flagged as "yellow," the second-most serious of four categories of violations.

The yellow flag triggered onsite NRC inspections in the fall of 2005. On Oct. 11, 2005, Units 2 and 3 were taken off line after NRC officials posed questions as to how the emergency cooling systems might operate under a range of hypothetical scenarios. The plants were brought back into service 10 days later, after the company successfully demonstrated that the cooling systems would operate as designed. An NRC inspection report related to the cooling system issues is expected in December 2005. Other operational problems have also occurred. In the spring of 2005, problems with the pressurizer heating elements in Unit 3 resulted in the extension of a planned 10-day outage to 32 days. In September, APS announced that day-to-day management of Palo Verde has been reorganized.

PWCC's consolidated cash coverage metrics are expected to be largely in line with 2004 results, which were very weak due to APS's delayed rate relief. For the 12 months ending Sept. 30, adjusted funds from operations (FFO) to interest coverage was 3.3x, identical to coverage at the end of 2004. The 12-month adjusted FFO to total debt was 14.8%, and reflects about $80 million in cash flows from Suncor assets sales that will not be realized in 2006 at this level. Future cash flow metrics will depend significantly on the ACC's actions, but are generally not expected to display any significant improvement through 2006 due to a continued build up of deferrals. Performance in 2007 will be heavily predicated on how long it takes for the ACC to rule on the company's base rate increase. Due in large part to PWCC's April 2005 issuance of $250 million in common stock, adjusted debt to total capitalization remains solid at 53% . However, borrowing requirements could rise in 2006 to fund APS's additional power and fuel costs deferrals and to invest in capital expenditures.

Short-term credit factors

PWCC's short-term rating is 'A-3'. The rating is supported by the preponderance of cash flows being produced by APS, a vertically integrated electric utility. Because of APS's sizable commercial paper program, near-term liquidity should be adequate to support cash outlays for power and fuel not recoverable in rates. And, because APS is heading into its winter season, when demand for electricity for space cooling drops significantly, the build-up of its power cost deferrals should slow. APS has hedged most of its power and gas purchases remaining in 2005, 85% of 2006 requirements, and about 65% for 2007.

Consolidated cash and investments stood at more than $900 million as of Sept. 30, 2005. However, $500 million was used on Oct. 3, 2005 to call Pinnacle West Energy Corp.'s (PWEC) floating-rate notes that were due April 2007. Also affecting the cash and invested position is the increased amount of collateral held under bilateral contracts.

PWCC and APS maintain commercial paper programs. Neither program had any balances as of Dec. 20, 2005. PWCC's program is for $250 million and is supported by a five-year, $300 million credit facility that expires in December 2010. The revolver allows PWCC to use up to $100 million of the facility for letters of credit. The revolver has no material adverse change clauses.

APS's short-term rating is also 'A-3'. The rating is supported by the stability of cash flows from regulated operations and good liquidity, although APS will need to continue to rely on borrowings to fund portions of its capital expenditure program, which is expected to be about $800 million in 2005 (and includes $190 million for the purchase of the Sundance power plant), up significantly from

$484 million in 2004. APS maintains a $250 million commercial paper program. APS has a five-year, $400 million revolver that expires in December 2010 that supports its commercial paper program, and also provides an additional $150 million for other liquidity needs, including $100 million for letters of credit. The supporting facility has no material adverse change clauses. Consolidated maturities are modest and consist of $384 million in 2006, of which $300 million is a note at the parent, which is due in April. Currently, there are virtually no obligations due in 2007, as PWEC called at par in early October some $500 million in notes that it issued in April 2005 to retire an intercompany loan between PWEC and APS that was associated with the PWEC assets now owned by APS.

Outlook

The stable outlook reflects Standard & Poor's expectation that the ACC will resolve at least a portion of APS's increasing deferred power costs in January 2006. In addition, the outlook presumes that progress will be made in addressing APS' general rate case and that any outcome will support the return of consolidated financial metrics to what until 2004 was a reasonable performance. The stable outlook is also dependent on improved 2006 performance at Palo Verde. Any adverse regulatory development or continued delays in resolving the pending surcharge request could result in a downward revision of the outlook or an adverse rating action. Because no meaningful improvement in the consolidated financial profile is expected in the near term, the potential for positive rating changes does not currently exist.

Ratings List

Ratings Lowered

Pinnacle West Capital Corp.	To	From
Corp credit rating	BBB-/Stable/A-3	BBB/Stable/A-2
Senior unsecured debt	BB+	BBB-
Commercial paper	A-3	A-2
Arizona Public Service Co.		
Corp credit rating	BBB-/Stable/A-3	BBB/Stable/A-2
Senior unsecured debt	BBB-	BBB
Commercial paper	A-3	A-2

APS-17

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TABLE OF CONTENTS

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Chairman and CEO
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Very truly yours,

Jean Bernhard Buttner

Jean B. Buttner,
Chairman & CEO

CHAPTER

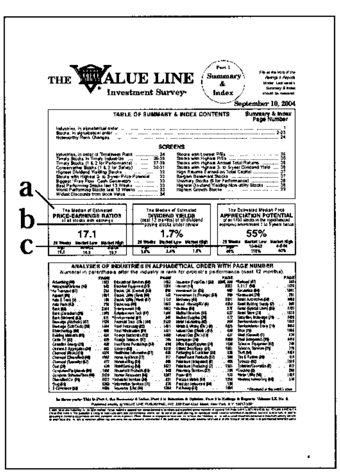
1

GETTING STARTED

How to use
The Value Line Investment Survey

The Value Line Investment Survey is a unique source of financial information designed to help investors make informed investment decisions that fit their individual goals and levels of risk. It is: (1) a proven forecaster of stock price performance over the next six to 12 months; (2) a source of interpretative analysis of approximately 1,700 individual stocks and more than 90 industries; and (3) a source of historical information that helps investors spot trends.

If you come across any unfamiliar terms as you read through this guide, please refer to the *Glossary* which begins on page 30.



Summary & Index

Part 1 - Summary & Index

Please start with the *Summary & Index.* The front cover contains a Table of Contents, three important market statistics, and a list of all the industries we follow in alphabetical order with the relative industry rank to the right of the industry name and the page number of the industry analysis in *Ratings & Reports* listed under PAGE. The market statistics are found in three boxes. The first box (**a**) has the median of estimated price/earnings ratios of all stocks with earnings in *The Value Line Investment Survey.* The second box (**b**) shows the median of estimated dividend yields (total dividends expected to be paid in the next 12 months divided by the recent price) of all dividend-paying stocks in *The Survey.* The third box (**c**) contains the estimated median price appreciation potential 3 to 5 years into the future for the approximately 1,700 stocks in *The Survey.* By studying these statistics, a fairly good picture emerges of how the universe of Value Line stocks is currently being evaluated. ***The Value Line universe of approximately 1,700 stocks has a market value of more than $14 trillion, and is quite representative of the whole stock market.***

Beginning on page 2, the *Summary & Index* also includes an alphabetical listing of all stocks in the publication with references to their location in Part 3, *Ratings & Reports.* If you are looking for a particular stock, look inside the *Summary & Index* section, which is updated each week to provide the most current data on all companies included in *The Value Line Investment Survey.*

To locate a report on an individual company, look for the page number just to the left of the company name. Then turn to that page in Part 3, *Ratings & Reports,* where the number appears in the upper right corner.

In the far left column of *Summary & Index* is a number that refers to recent Supplementary Reports, if any, which are included on the back pages of *Ratings & Reports.* If two asterisks (**) appear in this column, it means that there is a Supplementary Report in the current Issue.

There are many columns in the *Summary & Index* with more information on each of the approximately 1,700 stocks we cover, including from left to right:

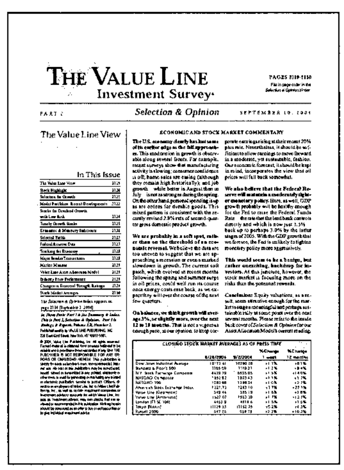
- page numbers for the latest company report and any recent Supplementary Report (Supplementary Reports are published at the back of *Ratings & Reports*)
- the name of each stock and the exchange on which it is traded (the New York Stock Exchange, unless otherwise indicated).
- each company's stock exchange (ticker) symbol
- the recent stock price (see the top of page 2 in *Summary & Index* under *Index to Stocks* for the specific date)
- Value Line's proprietary *Timeliness*™, *Safety*™ and *Technical*™ ranks (See Chapter 3 and the Glossary for definitions)
- Beta (a measure of volatility)
- each stock's 3- to 5-year Target Price Range and the % appreciation potential
- each stock's current P/E ratio
- each stock's % estimated dividend yield
- each stock's estimated earnings (approximately 6 months historical, 6 months estimated)
- each stock's estimated dividends for the next 12 months
- each stock's Value Line *Industry*™ rank (see Chapter 6)
- latest earnings and dividend declarations
- options trade indicator

There is also a wealth of information in the form of stock screens toward the back of the *Summary & Index*. The stock screens are a good place to start for anyone looking for investment ideas or help in forming a strategy. They are also useful for investors who want a list of stocks relevant to specific strategies they may have in mind.

Some examples of our useful screens are:

- Industries in Order of *Timeliness*
- Stocks Moving Up or Down in *Timeliness* Rank
- Timely Stocks in Timely Industries
- Conservative Stocks
- Highest Dividend Yielding Stocks
- Stocks with the Highest Estimated 3- To 5-Year Price Appreciation Potential
- Best/Worst Performing Stocks in the Past 13 Weeks
- Stocks With the Lowest and Highest P/E Ratios
- Stocks with the Highest Estimated Annual Total Returns (Next 3 To 5 Years)
- Stocks with the Highest Projected 3- To 5-year Dividend Yield
- Highest Growth Stocks (Definition Under The Title)

Part 2 - Selection & Opinion



Selection & Opinion

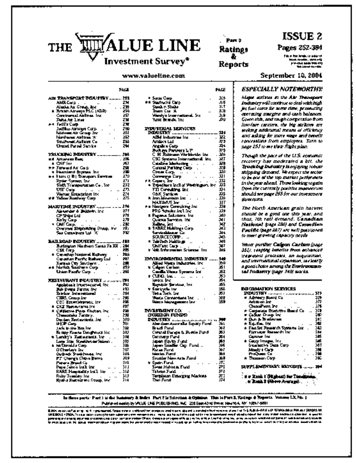
Selection & Opinion (S&O) contains Value Line's latest economic and stock market commentary and advice, along with one or more pages of research on interesting stocks or industries, and a variety of pertinent economic and stock market statistics. It also includes three model stock portfolios

(Stocks with Above-Average Year-Ahead Price Potential, Stocks for Income and Potential Price Appreciation, and Stocks with Long-Term Price Growth Potential). For more information on the portfolios, see page 26 in this Guide. If you spend time with *Selection & Opinion* each week, you should be able to get some valuable investment ideas.

Part 3 - Ratings & Reports

Ratings & Reports is the core of *The Value Line Investment Survey* with one-page reports on approximately 1,700 companies and one- or two-page reports on more than 90 industries. The company reports contain *Timeliness, Safety* and *Technical* ranks, our 3- to 5-year forecasts for stock prices, income and balance sheet data, as much as 17 years of historical data, and our analysts' commentaries. They also contain stock price charts; quarterly sales, earnings, and dividend information; and a variety of other very useful material. Each page in this section is updated every 13 weeks. When unexpected important news occurs during these 13 week intervals, a Supplementary Report (appearing in the back section of *Ratings & Reports)* is published. If there is a Supplementary Report, its page number will be shown in the far left hand column of the *Summary & Index*, near the company name.

Two asterisks — ** — indicate that a Supplementary Report is in this week's Edition.


THE VALUE LINE Investment Survey
Part 3 Ratings & Reports
ISSUE 2
September 10, 2004

Ratings & Reports

Every week subscribers receive a new Issue of *Ratings & Reports* containing approximately 135 company reports grouped by industry and a smaller number of one- or two-page industry reports. The industry reports precede the reports on the companies in that industry. Over the course of three months, new reports are issued on all of the approximately 1,700 companies and more than 90 industries.

CHAPTER

2

PLANNING AN INVESTMENT STRATEGY

Diversification

Most investors believe in owning a diversified portfolio of stocks, a strategy that Value Line strongly recommends. A diversified portfolio usually fluctuates less in its entirety than does an individual stock because the price variations of individual stocks tend to cancel each other out, with some moving up while others move down. It is also important to diversify not only among stocks, but also across industries.

For most individual investors, a practical rule for diversifying is to hold a total of at least ten stocks in approximately equal dollar amounts in at least ten or more different industries.

Creating a Diversified Portfolio

A good way to start is to turn to the screen called *Timely Stocks In Timely Industries*, usually found on page 25 of the *Summary & Index*.

This screen not only lists the industries that Value Line currently ranks highest (based on our *Timeliness Ranking System*, discussed in Chapter 3), but also the stocks that have the highest *Timeliness* ranks in those timely industries.

Select ten or more industries you think might be attractive from among those with the highest industry ranks. At this point, you may want to read the pages on specific industries to help you make a decision. The industry reports precede the reports on the companies in their industry. Then select one or two of the stocks ranked highest for *Timeliness* within each industry. The pages in *Ratings & Reports* examine these stocks in great detail.

Many of the stock screens in the back pages of the *Summary & Index* can be useful in creating a diversified portfolio. For instance, if you are interested in stocks of companies with growing sales, cash flow, earnings, dividends, and book value, study the Highest Growth Stocks screen. To be included in this list, a company's annual growth of sales, cash flow, earnings, dividends and book value must together have averaged 11% or more over the past 10 years and be expected to average at least 11% in the coming 3-5 years. There are many screens of stocks in the back section of the *Summary & Index* which will help you form a diversified portfolio. As mentioned elsewhere in this guide, *Selection & Opinion* also contains model portfolios which can be used to obtain ideas for any investor's portfolio.

CHAPTER

3

VALUE LINE'S RANKING SYSTEMS

The Value Line Investment Survey has a number of unique features that distinguish it from other advisory services and make it easier for you to have accurate, timely information so that you may keep up to date on all developments affecting your investments.

Probably the most famous are Value Line's time-honored ranking systems for *Timeliness* and *Safety*, which rank approximately 1,700 stocks relative to each other for price performance during the next six to 12 months. The newer Value Line *Technical Ranking System* is designed to predict short-term stock price movements. In each case, stocks are ranked from 1 to 5, with 1 being the highest ranking.

Note: *Any one Value Line stock rank is always relative to the ranks of all other stocks in the Value Line universe of approximately 1,700 stocks.*

Timeliness

The *Value Line* ***Timeliness*** rank measures relative probable price performance of all of the approximately 1,700 stocks during the next six to 12 months on an easy-to-understand scale from 1 (Highest) to 5 (Lowest). The components of the *Timeliness Ranking System* are the 10-year trend of relative earnings and prices, recent earnings and price changes, and earnings surprises. All data are actual and known. A computer program combines these elements into a forecast of the price change of each stock, relative to all other approximately 1,700 stocks for the six to 12 months ahead.

Rank 1 (Highest): These stocks, as a group, are expected to be the best performers relative to the Value Line universe during the next six to 12 months (100 stocks).

Rank 2 (Above Average): These stocks, as a group, are expected to have better-than-average relative price performance (300 stocks).

Rank 3 (Average): These stocks, as a group, are expected to have relative price performance in line with the Value Line universe (approximately 900 stocks).

Rank 4 (Below Average): These stocks, as a group, are expected to have below-average relative price performance (300 stocks).

Rank 5 (Lowest): These stocks, as a group, are expected to have the poorest relative price performance (100 stocks).

Changes in the *Timeliness* ranks can be caused by:

1. New earnings reports
2. Changes in the price movement of one stock relative to the approximately 1,700 other stocks in the publication
3. Shifts in the relative positions of other stocks

TIMELINESS	**2**	Raised 5/28/04
SAFETY	**1**	New 7/27/90
TECHNICAL	3	Lowered 8/6/04
BETA .65 (1.00 = Market)		

Ranks Box
(Also see item 1, on page 21)

Value Line's Timeliness Rank Record

The *Value Line Timeliness Ranking System* has been operating essentially in its present form since 1965. Its exemplary record has attracted the attention of academicians and has been the subject of numerous articles in scientific and financial journals.

Our performance record is discussed here and shown in the graphs on pages 9 and 10. The first shows that through December 2004 our 1-ranked stocks appreciated 49,441% (before commission costs and before dividends) since 1965. That compares with a gain of 1,082% for the Dow Jones Industrial Average. That is, if you consistently owned the one hundred stocks ranked number one out of the total of approximately 1,700, the portfolio, as a whole, would have appreciated more than 49,000%. The second graph shows that if you bought all our 1-ranked stocks at the beginning of January of each year, held them until the end of December, and then set up a new portfolio of 1-ranked stocks at the beginning of each subsequent year, the portfolio would have risen 19,715% since 1965. These are records we believe nobody else has ever matched.

Making Changes Weekly

Value Line has been calculating changes in the *Timeliness Ranking System* on a weekly basis for more than 37 years and has been publishing the results of those changes in *Selection & Opinion.* The record of weekly performance is outstanding and is shown in the chart and table on page 9. There you can see just how stocks ranked 1, 2, 3, 4, and 5 have done, assuming that all rank changes were implemented each week.

What you can clearly see is that there have been spectacular results not only for stocks in Groups 1 and 2, but also, in reverse, for those in Groups 4 and 5. You can see that our evaluations for *Timeliness* are equally effective in showing both good stocks to seek and poor ones to avoid.

Stocks ranked 1 and 2 for *Timeliness* cannot be expected to outperform the market in every single week or month. But over a longer period, the expectation that they will do so as a group is warranted, as our actual results demonstrate.

Making Annual (Once a Year) Changes

Most investors do not buy and sell stocks every week. Frequent "trading" may result in large commission costs. For these reasons, we have also regularly published a record of the results of annual changes in the *Timeliness Ranking System.* In what we call the "Frozen Record," we assume that investors buy stocks on the first business day of each year and hold them until the last day of the same year. Here, too, the top groups have consistently surpassed the growth of the other groups, as can be seen on page 10.

Safety

A second investment criterion is the *Safety* rank assigned by Value Line to each of the approximately 1,700 stocks. The *Value Line Safety* rank measures the total risk of a stock relative to the approximately 1,700 other stocks. It is derived from a stock's Price Stability rank and from the Financial Strength rating of a company, both shown in the lower right hand corner of each page in *Ratings & Reports.* Safety ranks are also given on a scale from 1 (safest) to 5 (riskiest) as follows:

> ***Rank 1 (Highest):*** These stocks, as a group, are the safest, most stable, and least risky investments relative to the Value Line universe, which accounts for about 95% of the market volume of all stocks in the U.S.
>
> ***Rank 2 (Above Average):*** These stocks, as a group, are safer and less risky than most.
>
> ***Rank 3 (Average):*** These stocks, as a group, are of average risk and safety.
>
> ***Rank 4 (Below Average):*** These stocks, as a group, are riskier and less safe than most.
>
> ***Rank 5 (Lowest):*** These stocks, as a group, are the riskiest and least safe.

Stocks with high *Safety* ranks are often associated with large, financially sound companies; these same companies also often have somewhat less than average growth prospects because their primary markets tend to be growing slowly or not at all. Stocks with low *Safety* ranks are often associated with companies which are smaller and/or have weaker than average finances; on the other hand, these smaller companies sometimes have above-average growth prospects because they start with a lower revenue and earnings base.

Value Line's Safety Rank Record

Safety becomes particularly important in periods of stock market downswings, when many investors want to try to limit their losses. As with *Timeliness*, the record of *Safety* over the years is impressive. When you study the data (shown in the table below), you will find that stocks with high *Safety* ranks generally fall less than the market as a whole when stock prices drop. The table shows how *Safety* ranks worked out in all major market declines between 1966 and the present.

The lesson is clear. If you think the market is headed lower, but prefer to maintain a fully invested position in stocks, concentrate on stocks ranked 1 or 2 for *Safety*. Also, at the same time, try to keep your portfolio ranked as high as possible for *Timeliness*. You may not be able to find stocks ranked high on both counts. You then must decide which is more important—price performance over the next six to 12 months, or *Safety*. A compromise of picking stocks ranked 1 or 2 for Timeliness and 1 or 2 for Safety may be necessary.

The Penalty and Reward of Risk

A risky stock is one which has low price stability and whose price fluctuates widely around its own long-term trend. It may also be a stock of a company with a low Financial Strength rating. One may reasonably assume that the price of a risky stock will go up more than that of a safe stock in a generally strong market. Yet, if in the interim it went down more sharply and you had to sell at an inopportune time, you could suffer a heavier penalty for having bought the high-risk stock instead of the safer one.

High Value Line *Timeliness* ranks give some protection against a general market decline, but only over a period of six to 12 months. They cannot be relied upon to help protect against a sharp drop in the stock market in every week or month, as a high *Safety* rank may often do.

Technical

The Value Line *Technical* rank uses a proprietary formula to predict short-term (three to six month) future price returns relative to the Value Line universe. It is the result of an analysis which relates 10 price trends of different duration for a stock during the past year to the relative price changes of the same stock expected over the succeeding three to six months. The *Technical* rank is best used as a secondary investment criterion. We do not recommend that it replace the *Timeliness* rank. As with the other ranks, the *Technical* rank goes from 1 (Highest) to 5 (Lowest.)

RESULTS OF SAFETY RANKS IN MAJOR MARKET DECLINES

Safety Rank	2/11/66– 10/7/66–	12/13/68– 7/2/70–	4/14/72– 9/11/74–	6/17/81– 8/11/82–	8/26/87– 12/4/87–	7/13/90– 11/2/90–	4/22/98– 10/08/98–	5/22/01– 9/21/01	4/16/02– 10/9/02
Group 1	−15.6%	−28.6%	−40.5%	−10.5%	−24.7%	−19.0%	−6.1%	−11.5%	−20.8%
Group 2	−18.2	−29.6	−39.9	−16.2	−28.7	−15.5	−14.0	−14.0	−23.8
Group 3	−24.0	−41.1	−47.2	−25.2	−36.0	−24.9	−29.7	−23.4	−33.1
Group 4	−26.5	−57.0	−53.3	−33.6	−40.7	−33.2	−41.7	−41.7	−55.2
Group 5	−29.2	−64.8	−70.0	−31.4	−46.9	−33.1	−37.8	−34.3	−51.7

The results of the *Technical* ranks since the beginning of 1984, are shown below. From that data, we can calculate that from December 31, 1983, through December 2002, the stocks with a *Technical* ranks of 1 rose 1105%. Those ranked 5 rose just 17%. By way of comparison, the Standard & Poor's 500 Stock Index, a recognized measure of broad stock market performance, was up 433% in the same period.

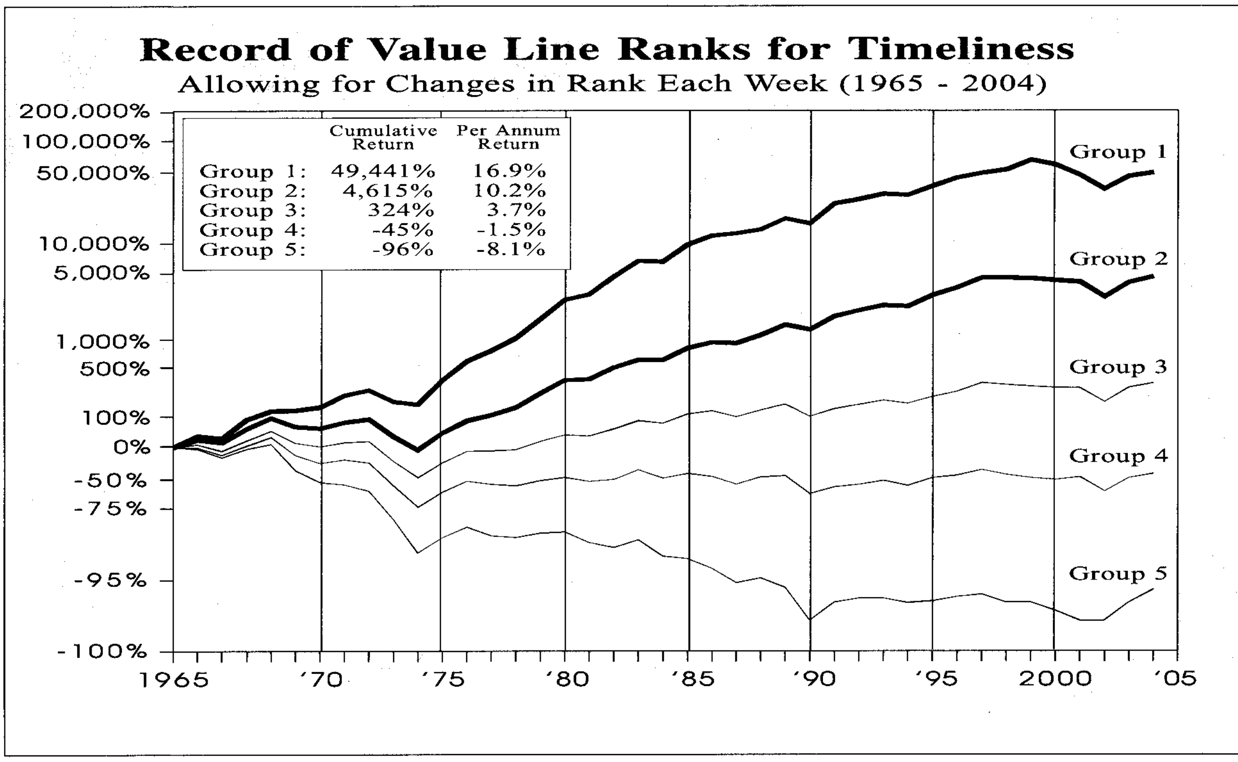
Industry

Value Line also publishes *Industry* ranks which show the *Timeliness* of each industry. These ranks are updated weekly and published on the front and inside pages of the *Summary & Index.* They also appear at the top of each Industry Report. The *Industry* Rank is calculated by averaging the *Timeliness* ranks of each of the stocks which have been assigned a *Timeliness* rank in a particular industry. For more information, see page 22.

RECORD OF TECHNICAL RANKS (*QUARTERLY REBALANCING*)

	1	2	3	4	5
1984	-14.9%	-8.8%	-6.0%	-5.5%	0.0%
1985	42.5	32.3	28.1	19.7	4.5
1986	36.6	25.0	18.4	4.5	-11.7
1987	-7.7	-6.2	-6.7	-5.8	-18.2
1988	11.2	13.3	16.0	22.2	10.1
1989	27.6	25.0	19.9	9.0	-15.6
1990	-15.2	-11.2	-14.6	-28.5	-45.6
1991	61.9	32.1	31.7	44.5	43.5
1992	19.7	12.1	11.4	9.9	12.4
1993	41.5	21.7	12.3	14.7	19.2
1994	-1.4	-3.1	-2.3	-3.4	-7.6
1995	31.1	27.2	24.6	16.7	11.0
1996	21.5	22.6	16.6	15.0	19.3
1997	40.4	31.6	24.9	22.5	8.7
1998	26.5	16.9	2.5	-6.9	-8.8
1999	70.0	17.6	1.1	-0.5	8.7
2000	-7.0	10.1	12.9	12.2	-7.3
2001	-5.3	7.6	9.8	22.9	34.6
2002	-42.9	-25.8	-14.2	-8.3	-3.4
2003	57.2	39.2	38.4	55.3	122.9
2004	21.8	15.3	15.6	16.4	19.5
TOTAL	**2207**	**1133**	**712**	**550**	**211**
S&P:	**635**				

BUYING AND SELLING STOCKS EACH WEEK



RECORD OF VALUE LINE RANKINGS FOR TIMELINESS (ALLOWING FOR CHANGES IN RANK EACH WEEK)†

April 16, 1965 to December 31, 2004

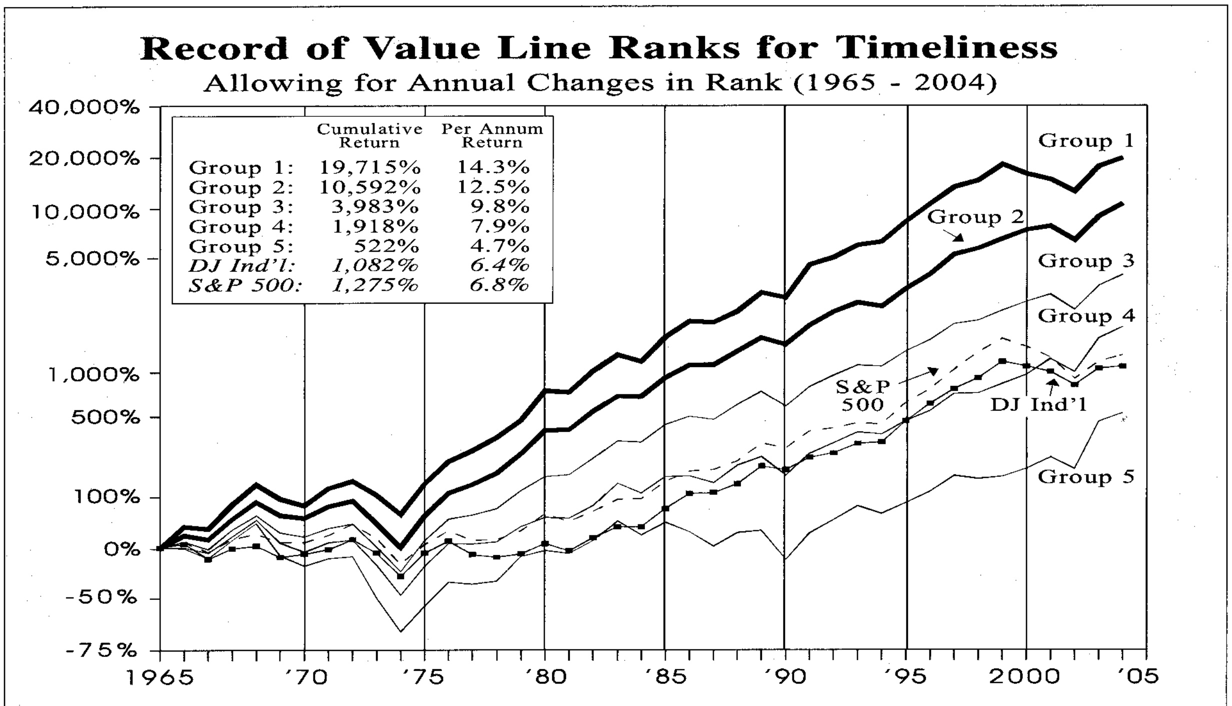
Group	'65*	'66	'67	'68	'69	'70	'71	'72	'73	'74	'75	'76	'77	'78	'79	'80	'81	'82	'83	'84	'85
1	28.8%	-5.5%	53.4%	37.1%	-10.4%	7.3%	30.6%	12.6%	-19.1%	-11.1%	75.6%	54.0%	26.6%	32.6%	54.7%	52.6%	13.6%	50.6%	40.9%	-2.1%	47.0%
2	18.5	-6.2	36.1	26.9	-17.5	-3.2	13.7	7.4	-28.9	-29.5	47.4	31.2	13.4	18.3	38.0	35.7	1.8	31.0	19.1	-0.8	30.7
3	6.7	-13.9	27.1	24.0	-23.8	-8.0	9.3	3.5	-33.6	-34.1	40.7	29.0	1.3	3.0	20.7	15.4	-3.3	17.9	20.2	-5.6	22.8
4	-0.4	-15.7	23.8	20.9	-33.3	-16.3	8.4	-7.1	-37.9	-40.6	39.3	28.8	-6.9	-3.8	12.8	7.4	-8.7	5.1	25.0	-17.4	11.4
5	-3.2	-18.2	21.5	11.8	-44.9	-23.3	-5.5	-13.4	-43.8	-55.7	40.9	26.7	-17.6	-3.2	10.4	2.9	-21.4	-10.9	19.0	-31.0	-5.6

Group	'86	'87	'88	'89	'90	'91	'92	'93	'94	'95	'96	'97	'98	'99	'00	'01	'02	'03	'04	'65* to 2004
1	22.9%	5.4%	9.5%	27.9%	-10.4%	55.4%	10.0%	13.4%	-2.6%	22.8%	20.4%	11.3%	8.2%	24.1%	-10.4%	-20.3%	-27.2%	33.8%	8.4%	49,441%
2	14.4	-2.4	20.4	26.5	-10.2	34.1	14.3	12.4	-2.2	28.1	19.0	24.0	0.1	-0.5	-4.4	-3.8	-28.8	38.2	14.5	4,615
3	7.7	-12.6	16.1	13.7	-24.4	18.9	11.0	9.8	-6.9	16.6	12.3	21.5	-3.9	-3.3	-3.2	-0.8	-27.1	38.2	10.5	324
4	-6.8	-15.8	17.6	2.6	-33.7	16.7	6.2	8.5	-9.9	17.1	7.1	14.5	-11.0	-7.5	-3.7	5.9	-26.7	34.2	9.4	-45
5	-19.6	-28.0	11.4	-19.2	-45.5	25.5	15.4	0.3	-15.2	5.2	7.5	16.6	-11.5	-1.3	-19.7	-7.2	-15.7	52.2	15.2	-96

* *April through December*

† *Geometric Averaging*

BUYING STOCKS AT THE BEGINNING OF EACH YEAR



RECORD OF VALUE LINE RANKINGS FOR TIMELINESS (WITHOUT ALLOWING FOR CHANGES IN RANK EACH WEEK)†

April 16, 1965 to December 31, 2004

Group	'65*	'66	'67	'68	'69	'70	'71	'72	'73	'74	'75	'76	'77	'78	'79	'80	'81	'82	'83	'84	'85
1	33.6%	-3.1%	39.2%	31.2%	-17.7%	-8.9%	26.5%	10.1%	-17.1%	-23.1%	51.6%	35.3%	15.8%	19.8%	25.6%	50.2%	-1.9%	33.7%	25.2%	-8.6%	38.6%
2	18.9	-6.0	31.9	26.3	-16.3	-4.0	17.4	7.5	-26.2	-27.8	53.0	36.3	12.7	16.1	30.8	37.4	0.7	29.0	22.2	-0.1	29.5
3	8.9	-9.7	30.1	21.4	-20.7	-5.5	12.2	6.2	-27.0	-28.5	52.9	33.8	5.2	9.2	27.6	20.8	2.7	25.5	26.7	-1.6	26.6
4	0.8	-7.2	25.1	25.1	-26.8	-11.7	14.2	3.2	-29.1	-33.6	48.4	36.1	-0.2	2.4	23.1	13.2	-0.9	18.1	35.2	-12.3	24.6
5	-1.2	-12.4	28.4	25.9	-35.7	-13.1	10.5	2.9	-43.1	-36.8	42.1	38.2	-2.8	4.0	39.9	8.4	-4.2	19.9	30.0	-17.1	18.7
Avg.	10.1	-7.9	29.9	24.6	-22.1	-7.5	14.9	5.5	-27.7	-29.6	51.2	35.1	5.8	9.6	28.0	23.4	0.9	25.0	27.5	-4.7	27.0

Group	'86	'87	'88	'89	'90	'91	'92	'93	'94	'95	'96	'97	'98	'99	'00	'01	'02	'03	'04	'65* to 2004
1	23.5%	-1.2%	16.0%	28.7%	-6.6%	56.7%	10.1%	18.5%	4.6%	31.3%	27.0%	25.8%	9.3%	23.7%	-11.7%	-7.4%	-15.0%	40.1%	12.2%	19,715%
2	18.7	0.4	19.7	20.3	-8.7	29.8	19.9	13.6	-5.3	27.1	21.4	31.3	8.5	13.9	13.2	4.8	-17.3	37.9	18.8	10,592
3	11.5	-4.1	23.2	19.6	-18.6	30.0	17.5	15.3	-1.6	22.8	16.1	24.1	4.8	14.5	13.0	10.2	-18.8	38.6	15.8	3,983
4	1.5	-9.1	27.2	12.4	-22.8	34.1	15.6	16.5	-2.9	20.2	14.3	26.6	0.6	13.5	14.0	23.3	-16.2	58.2	16.5	1,918
5	-12.1	-17.9	20.0	3.3	-33.0	43.8	19.9	20.3	-9.3	15.7	15.8	24.4	-4.0	2.8	11.6	16.4	-14.5	90.1	12.3	522
Avg.	10.2	-4.9	22.6	17.8	-17.6	33.4	17.3	15.7	-2.6	23.2	17.4	26.1	4.4	14.0	11.4	11.0	-17.5	45.4	16.0	4,264

* *April through December*

† *Arithmetic Averaging*

Dow Jones Industrials 1,082%

S&P 500 1,275%

CHAPTER

4

UNDERSTANDING THE VALUE LINE PAGE

To start studying a stock, we suggest that you concentrate on four features found on every *Ratings & Reports* page (*see sample on page 21 of this guide*). First, we recommend that you look at the *Timeliness, Safety,* and *Technical* ranks (*see item 1*) shown in the upper left corner of each page. Then, read the Analyst's Commentary (*item 17*) in the bottom half of each report. Next, we suggest you look at our forecasts for various financial data including the stock price (*items 11, 15, 22, 23, and 29*). These forecasts are explained in more detail later in this Chapter. Finally, we think you should study the historical financial data appearing in the Statistical Array in the center of the report (*item 26*). Illustrations and more detail follow. There is also a lot of other useful information on each page, but the four features mentioned above provide the best place to begin.

TIMELINESS	**2**	Raised 5/28/04
SAFETY	**1**	New 7/27/90
TECHNICAL	3	Lowered 8/6/04
BETA .65 (1.00 = Market)		

Ranks Box
(Also see item 1, on page 21)

Value Line Ranks

(*See* 1 *in the example on page 21)*

A synopsis of the *Value Line Ranking System* follows. For a more detailed description, please refer to Chapter 3.

Timeliness

The *Timeliness* rank is Value Line's measure of the expected price performance of a stock for the coming six to 12 months relative to our approximately 1,700 stock universe. Stocks ranked 1 (Highest) and 2 (Above Average) are likely to perform best relative to the others. Stocks ranked 3 are likely to be average performers relative to the Value Line universe. Stocks ranked 4 (Below Average) and 5 (Lowest) are likely to underperform stocks ranked 1 through 3 in Value Line's stock universe.

Just one word of caution. Stocks ranked 1 are often volatile and tend to have smaller market capitalizations (the total value of a company's outstanding shares, calculated by multiplying the number of shares outstanding by the stock's market price per share). Conservative investors may want to select stocks that also have high *Safety* ranks because they are usually more stable issues.

Safety

The *Safety* rank is a measure of the total risk of a stock compared to others in our approximately 1,700 stock universe. As with *Timeliness,* Value Line ranks each stock from 1 (Highest) to 5 (Lowest). However, unlike *Timeliness,* the number of stocks in each category from 1 to 5 is not fixed. The *Safety* rank is derived from two measurements (weighted equally) found in the lower right hand corner of each page:

a company's Financial Strength and a Stock's Price Stability. Financial Strength is a measure of the company's financial condition, and is reported on a scale of A++ (Highest) to C (Lowest). The largest companies with the strongest balance sheets get the highest scores. A Stock's Price Stability score is based on a ranking of the standard deviation (a measure of volatility) of weekly percent changes in the price of a stock over the last five years, and is reported on a scale of 100 (Highest) to 5 (Lowest) in increments of 5.

Technical

The *Technical* rank is primarily a predictor of short term (three to six months) relative price change. It is based on a proprietary model which examines 10 short-term price trends for a particular stock over different periods in the past year. The *Technical* ranks also range from 1 (Highest) to 5 (Lowest). At any one time, approximately 100 stocks are ranked 1; 300 ranked 2; 900 ranked 3; 300 ranked 4; and 100 ranked 5.

Beta

This is a measure of volatility, as calculated by Value Line. While it is not a rank, we do consider it important. See the *Glossary* for more detail.

Analyst's Commentary

(17 in the example on page 21)

Next, look at the analyst's written commentary in the lower half of the page. Many readers think this is the most important section of the page. In the commentary, the analyst discusses his/her expectations for the future. There are times when the raw numbers don't tell the full story.

Johnson & Johnson topped expectations in 2004's initial half, and we've raised our earnings estimate for the year. In the March quarter, the company beat our $0.82 bottom-line estimate by a penny, with net rising 20%. It exceeded our figure by $0.02 (and consensus by $0.03) in the second period, posting a 17% year-over-year increase. Revenues were up 11.3% in the most recent quarter, 8.5% on a constant currency basis. Significantly, too, sales growth was solid across all three major businesses, with pharmaceuticals, medical devices & diagnostics, and consumer expanding by 11.1% (to $5.4 billion), 11.8% ($4.1 billion), and 10.0% ($2.0 billion), respectively. An enriched sales mix, meantime, along with cost-cutting initiatives, added 1.2 percentage points to the gross margin. In view of both the outperformance and the receding prospect of generic rivals for *Duragesic*, we've upped (by $0.06) our estimate for 2004 to $3.03, in line with management's guidance.
The bottom-line advance will likely continue to decelerate, though, slowing into single-digit territory in 2005. Sales of *Procrit/Eprex*, J&J's best-seller, are under substantial competitive and pricing pressures, as underscored by a 14% (or $137 million) drop in the June quarter. Top-line contributions from another key growth driver, *Cypher* (drug eluting stent), is also being squeezed mightily, by Boston Scientific's *Taxus*, which was launched in March. And, early next year, *Duragesic*, which we estimate will add about $2 billion to 2004 sales, will undoubtedly face stiff competition from generics. J&J has a decent new-drug pipeline, but we think the share-net advance will be about 9% in 2005, compared with 12% this year and 21% in 2003.
These top-quality shares still deserve consideration. The healthcare products giant has almost $11 billion in cash. As well, it generates some $6 billion annually in free cash flow. Thus, management has ample financial flexibility with which to transfigure the company's growth profile. Major acquisitions and/or stock repurchases are clearly viable options. J&J stock is timely for the year ahead. Moreover, it also offers good risk-adjusted, 3- to 5-year total-return potential.
George Rho *September 3, 2004*

Analyst's Commentary

(Also see item 17, on page 21)

The analyst uses the commentary to explain why the forecast is what it is. The commentary is also particularly useful when a change in trend is occurring or about to occur. As an example, a stock may have a poor *Timeliness* rank but the analyst thinks earnings could turn around in the future. In this case, the analyst may use the commentary to explain why he/she thinks conditions are likely to get better, thus giving the subscriber insight into what is happening, and why.

Financial and Stock Price Projections

Value Line's security analysts make a variety of financial and stock price projections in most reports we publish. They make ***Estimates*** for 23 different numbers and ratios going out 3 to 5 years into the future in the Statistical Array (*item 15*). They also forecast a ***Target Price Range*** (*item 11*) for each stock, going out 3 to 5 years. And finally they show the ***2007-09 Projections*** (*item 29*) for the price of the stock, along with the expected percentage appreciation (depreciation) and the expected annual total return (including dividends). These projections are discussed below.

Financial Estimates

(15 in the example on page 21)

1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	© VALUE LINE PUB., INC.	07-09
3.38	3.66	4.22	4.67	5.25	5.50	6.12	7.27	8.11	8.41	8.80	9.88	10.47	10.83	12.23	13.42	***15.60***	***16.70***	Sales per sh A	***21.40***
.51	.56	.65	.73	.85	.93	1.06	1.26	1.46	1.62	1.83	2.03	2.27	2.46	2.65	2.91	***3.75***	***4.10***	"Cash Flow" per sh	***5.50***
.36	.41	.48	.55	.62	.69	.78	.93	1.09	1.21	1.34	1.49	1.70	1.91	2.23	2.70	***3.03***	***3.30***	Earnings per sh B	***4.50***
.12	.14	.16	.19	.22	.25	.28	.32	.37	.43	.49	.55	.62	.70	.80	.93	***1.10***	***1.21***	Div'ds Decl'd per sh ■C	***1.58***
.25	.28	.31	.37	.42	.38	.36	.46	.52	.52	.54	.62	.59	.57	.71	.73	***.75***	***.80***	Cap'l Spending per sh	***1.00***
1.31	1.56	1.84	2.11	1.97	2.17	2.77	3.49	4.07	4.59	5.06	5.83	6.76	7.95	7.65	8.61	***10.75***	***12.65***	Book Value per sh D	***19.55***
2664.6	2664.4	2664.6	2665.3	2621.6	2571.9	2572.0	2590.7	2665.0	2690.3	2688.1	2779.4	2781.9	3047.2	2968.3	3119.8	***2960.0***	***2950.0***	Common Shs Outst'g E	***2900.0***
14.2	15.4	16.5	20.5	20.0	15.4	14.8	18.5	22.4	24.9	28.1	31.6	26.4	27.2	25.9	21.9	***Bold figures are Value Line estimates***		Avg Ann'l P/E Ratio	***20.0***
1.18	1.17	1.23	1.31	1.21	.91	.97	1.24	1.40	1.44	1.46	1.80	1.72	1.39	1.41	1.27			Relative P/E Ratio	***1.35***
2.4%	2.2%	2.1%	1.7%	1.8%	2.4%	2.4%	1.9%	1.5%	1.4%	1.3%	1.2%	1.4%	1.3%	1.4%	1.8%			Avg Ann'l Div'd Yield	***1.8%***

CAPITAL STRUCTURE as of 6/27/04
Total Debt $3,453 mill. **Due in 5 Yrs** $*500.0* mill.
LT Debt $2,962 mill. **LT Interest** $174.0 mill.
(9% of Cap'l)
Leases, Uncapitalized Annual rentals $143.0 mill.

Pension Assets-12/02 $6,050 mill. **Oblig.** $7,680 mill.
Pfd Stock None

Common Stock 2,968,107,066 shs.
as of 7/25/04

MARKET CAP: $171 billion (Large Cap)

CURRENT POSITION 2002 2003 6/27/04
($MILL.)

1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	© VALUE LINE PUB., INC.	07-09
15734	18842	21620	22629	23657	27471	29139	33004	36298	41862	***46165***	***49200***	Sales ($mill) A	***62000***
22.4%	23.2%	24.6%	25.1%	26.6%	27.0%	27.4%	28.8%	31.2%	30.5%	***31.5%***	***32.0%***	Operating Margin	***33.5%***
724.0	857.0	1009.0	1067.0	1246.0	1444.0	1515.0	1605.0	1662.0	1869.0	***2050***	***2190***	Depreciation ($mill)	***2725***
2006.0	2403.0	2887.0	3303.0	3677.6	4209.0	4800.0	5885.0	6810.8	7197.0	***9090***	***9865***	Net Profit ($mill)	***13165***
25.2%	27.6%	28.4%	27.8%	27.1%	27.5%	27.5%	28.2%	29.0%	30.2%	***28.5%***	***28.0%***	Income Tax Rate	***27.5%***
12.7%	12.8%	13.4%	14.6%	15.5%	15.3%	16.5%	17.8%	18.8%	17.2%	***19.7%***	***20.1%***	Net Profit Margin	***21.3%***
2414.0	3550.0	4186.0	5280.0	2970.0	5746.0	8310.0	10429	7817.0	9547.0	***14500***	***16780***	Working Cap'l ($mill)	***24500***
2199.0	2107.0	1410.0	1126.0	1269.0	2450.0	2037.0	2217.0	2022.0	2955.0	***2500***	***2000***	Long-Term Debt ($mill)	***1500***
7122.0	9045.0	10836	12359	13590	16213	18808	24233	22697	26869	***31750***	***37350***	Shr. Equity ($mill)	***56760***
22.3%	22.3%	24.2%	24.9%	25.2%	22.9%	23.3%	22.5%	27.8%	24.4%	***26.0%***	***24.0%***	Return on Total Cap'l	***22.0%***
28.2%	26.6%	26.6%	26.7%	27.1%	26.0%	25.5%	24.3%	30.0%	26.8%	***28.5%***	***26.5%***	Return on Shr. Equity	***23.0%***
18.0%	17.4%	17.7%	17.5%	17.5%	16.8%	16.4%	15.8%	19.5%	16.6%	***18.0%***	***14.0%***	Retained to Com Eq	***15.0%***
36%	34%	34%	34%	35%	35%	36%	35%	35%	38%	***36%***	***37%***	All Div'ds to Net Prof	***35%***

Statistical Array

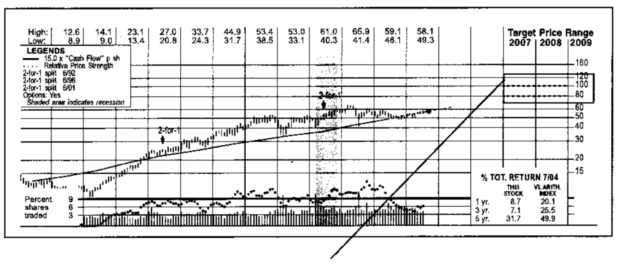
(Also see items 15 and 26, on page 21)

In the Statistical Array in the center of the report (where most of the numbers are), Value Line provides both historical data and financial projections. All projections are printed in ***bold italics***.

The estimates of sales, earnings, net profit margins, income tax rates, and so forth are all derived from spread sheets maintained on every company. Our analysts try to review their projections with a company's management whenever they think they should, but at least once a quarter. Afterward, they make whatever adjustments they believe are warranted by unusual developments that may not be revealed in the numbers, i.e., the outcome of pending lawsuits affecting the company's finances, the success of new products, etc.

Target Price Range

In the upper right-hand section of each report is a *Target Price Range.* The *Target Price Range* represents the band in which the expected average price is likely to fall.



Target Price Range (3 to 5 years)
(*Also see item 11, on page 21*)

This is the projected annual stock price range for the period out 3 to 5 years. The prices are based on the analyst's projections in the period out 3-5 years for earnings multiplied by the average annual price/earnings ratio in the Statistical Array for the same period. The width of the high-low range depends on the stock's *Safety* rank. (A stock with a high *Safety* rank has a narrower range, one with a low rank, a wider band.)

3- to 5- Year Projections
(Item 29, on page 21)

In the left hand column of each report, there is also a box which contains 2007-2009 *Projections* for a stock price. There you can see the potential average high and low prices we forecast, the % price changes we project, and the expected compound annual total returns (price appreciation plus dividends). To make these calculations, analysts compare the expected prices out 3 to 5 years into the future (as shown in the *Target Price Range* and *Projections* box) with the recent price (shown on the top of the report).

2007-09 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+75%)	*16%*
Low	80	(+40%)	*10%*

2006-08 Projections
(*Also see item 29, on page 21*)

Investors whose primary goal is long-term price appreciation should study the 3- to 5-year *Projections* carefully and choose stocks with above-average price appreciation potential. For comparative purposes, you can find the weekly Estimated Median Price Appreciation Potential for all approximately 1,700 stocks on the front page of the *Summary & Index.*

The *Target Price Range* and 3-to 5-year *Projections* are necessarily based upon an estimate of future earnings. They are, therefore, very subjective. These should not be confused with the *Timeliness* rank for 12-month performance, which is independent of estimates and based solely on historical data.

Annual Rates Of Change
(Item 23, on page 21)

At this point, it may be helpful to look at the *Annual Rates* box in the left-hand column. This box shows the compound annual per share growth percentages for sales, "cash flow," earnings, dividends and book value for the past 5 and 10 years and also Value Line's projections of growth for each item for the coming 3 to 5 years. All rates

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '01-'03 to '07-'09
Sales	9.0%	7.5%	*10.0%*
"Cash Flow"	12.5%	11.0%	*12.5%*
Earnings	13.5%	12.5%	*12.0%*
Dividends	13.5%	13.5%	*12.0%*
Book Value	14.5%	12.0%	*16.0%*

Annual Rates Box
(*Also see item 23, on page 21*)

of change are computed from the average number for a past 3-year period to an average number for a future period. For details, see below.

Trends are important here. Check whether growth has been increasing or slowing and see if Value Line's analyst thinks it will pick up or fall off in the future. Specific estimates for various data items for 3 to 5 years out can be found in ***bold italics*** print in the far right hand column of the Statistical Array (item 15).

Historical Financial Data

(26 in the example on page 21)

Many investors like to use the Statistical Array to do their own analysis. They, in particular, use the historical data in the center of each report to see how a company has been doing over a long time frame. It is worth pointing out that while all of the data are important, different readers find different data items to be most useful.

The numbers are probably most helpful in identifying trends. For example, look at sales per share to see if they have been rising for an extended period of time. Look at operating margins and net profit margins to see if they have been expanding, narrowing or staying flat. And examine some of the percentages near the bottom, such as the Return on Shareholders' Equity, to see if they have been rising, falling, or remaining about the same.

Calculating Annual Rates of Change

(Growth Rates)

In an attempt to eliminate short-term fluctuations that may distort results, Value Line uses a three-year base period and a three-year ending period when calculating growth rates.

Example: To calculate the compound annual sales growth from 2001-2003 (the latest years for which reported actual financial results were available when our Johnson & Johnson report on page 21 went to press) to 2007-2009, we take sales per share for each of the years 2001, 2002, and 2003 and average them. Then we take the sales per share for the years 2007-2009, as shown in the far right column of the large statistical section of our report.

In the case of Johnson & Johnson, the three-year base period average is \$12.16. The three-year ending period average is \$21.40. The compound annual growth rate over the seven years from 2002 (the middle year) to 2008 (again, the middle year) is 10.0%, rounded.

Investors often try to calculate a growth rate from one starting year to one ending year, and then can't understand why the number they get is not the same as the one published by Value Line. If they used a three-year base period and three-year ending period, they would get the same results we do.

CHAPTER

5

EXAMINING A VALUE LINE PAGE IN MORE DETAIL

In the following section, we are going to examine an actual Value Line page, with the objectives of interpreting the array of statistical data presented and weighing the data and the accompanying comment against your needs. We have chosen for examination a report on Johnson & Johnson, a large and well known manufacturer of health care products.

Putting Data in Perspective

Looking at the top of the page, we can see that Johnson & Johnson's stock price in September 2004 was $57.66 a share (item 5 on page 21). By itself, the stock price means very little. In the line below the price, annual high and low prices for each year from 1993 through late 2004 are indicated. Below the high and low annual prices is a price chart (graph) that shows monthly price ranges for essentially the same period, along with other useful information that we will discuss below. We note here, though, that while Johnson & Johnson stock has traded in a relatively narrow range for nearly four years, it has still climbed more than sixfold from its low of 8.9 in 1993 (adjusted for stock splits in 1996 and 2001).

Is the fact that the stock has moved up so much cause for concern? Has it become overvalued? Not necessarily—as we will see. Sales per share, cash flow per share, earnings per share, and book value per share are all at historical highs, as can be seen in the Statistical Array (items 15 and 26 on page 21).

Price Earnings Ratio—This is probably the most widely used measure of stock valuation. Value Line shows a variety of P/E ratios on every company page, as discussed below:

The *P/E ratio* on the very top of the Value Line page (item 6 on page 21). This is calculated by dividing the recent price of the stock by the total of the last six months of earnings and the next six months of estimated earnings.

The *Relative P/E ratio* (item 8). This compares the P/E of one stock with the median of estimated P/E ratios of all stocks under Value Line review. A relative P/E of more than 1 indicates that a stock's P/E ratio is currently higher than that of the Value Line universe; a P/E of less than 1 indicates that this stock's P/E is less than the Value Line average.

The *Trailing P/E ratio* (item 7). This is calculated by dividing the recent price of the stock by the past 12 months of actual (reported) earnings. This is the figure shown in most newspapers.

The *Median P/E ratio* (item 7). This is the average annual P/E ratio of a stock over the past 10 years, with certain statistical adjustments made for unusually low or high ratios.

The *Average Annual P/E ratio* (items 15 and 26). This figure is calculated by dividing the average price for each year by the actual reported earnings for the same year and is shown in the Statistical Array.

The *Relative (Annual) P/E ratio* (items 15 and 26). This figure is calculated by dividing the *Average Annual P/E* of a stock with the *Average Annual P/E* of all stocks under Value Line review in the same year.

To gauge the significance of the recent price of a stock, the reader must look at the price in relation to a variety of data. As far as P/Es are concerned, the current P/E ratio and relative P/E ratio for Johnson & Johnson's stock, while above those of most stocks in the Value Line universe, are still quite close to the Value Line median P/E. These slightly above-average valuations underscore investors' long standing favor for this equity.

High P/E ratios may mean that the stock is overpriced, unless there are factors indicating that there will be a significant improvement in the company's fundamentals. Is this the case with Johnson & Johnson? Perhaps, since management has been very vigilant in its efforts to maximize returns from its businesses, and the Value Line analyst is expecting continued strong profit growth over the next three to five years. High growth rates often result in above-average price/earnings ratios. Johnson & Johnson's relative P/E ratio of 1.09 (item 8), a slightly richer valuation than found in the average stock followed by Value Line, also likely reflects the company's track record and growth expectations.

The *Dividend Yield* (item 10 in the right top corner of the page) shows the expected return from cash dividends on the stock over the next 12 months, as a percentage of the recent price. Johnson & Johnson's yield of 2.0% is above the median of all dividend paying stocks in the Value Line Universe. (The median is shown each week on the cover of the *Summary & Index* section.) We also see that the company has increased the dividend in every year since 1988, as shown in line four of the Statistical Array in the center of our report, and Value Line's analyst thinks additional increases are forthcoming. Many investors view regular increases in a dividend very positively.

The Price Chart

Next, look at Johnson & Johnson's price chart (or graph) at the top of the report. The first thing to look at is the price history, shown by the small vertical bars in the center of the graph. Those bars show the high and low monthly prices for the stock (adjusted for any subsequent stock splits or dividends). Looking at the bars, you can see that the stock price was in a strong uptrend from 1994 through 1999. Since then, it has traded in a broad range, generally between 40 and 60.

Stock Price History
Cash Flow Price Line
Relative Price Strength

Now look at the "cash flow" line, the solid line running from 1992 through the middle of 2003, which is more fully described below. The dashed line from mid-2003 to mid-2005, which is an extension of the "cash flow" line, is Value Line's projection of the line for those years. For most of the past nine years, Johnson & Johnson's stock has traded above the "cash flow" line. More recently, the stock has moved back down to the line.

Finally, look at the *Relative Strength Price* line, the faint small dotted line, usually toward the bottom of the chart. This shows the relative performance of Johnson & Johnson stock versus the entire universe of Value Line stocks; when the *Relative Strength Price* line is rising, it means a stock is acting better than the universe. When it is falling, a stock is doing worse than the Value Line universe.

At the very bottom of the chart, we show volume of trading each month (item 14) as a percent of total shares outstanding. The *Legends* box (item 2) in the upper left of the price chart contains, among other things, information on the "cash flow" multiple, a record of stock splits, and whether or not there are options traded.

The *Target Price Range* (item 11) in the upper right corner of the price chart indicates where Value Line's analyst believes the stock is most likely to be selling in the 2007-09 period. This box should be viewed in conjunction with the *Projections* box (item 29) near the top left-hand corner of the page, which also gives our 3- to 5-year projections. For Johnson & Johnson, we expect the average price to hover between 80 and 100, which would be moderately above the current level.

Just above the 2007-09 PROJECTIONS box is a section containing the Value Line *Timeliness, Safety,* and *Technical* ranks, plus a Beta calculation. Johnson & Johnson's Beta of .65 reveals that this stock is likely to move up and down much more slowly than the typical stock on the New York Stock Exchange. If you think that the stock market will go up, you want to invest in stocks with high Betas. If you think the market will go down or are looking for stability, a stock like Johnson & Johnson, with a low Beta is the place to be.

The "Cash Flow" Line

The price chart at the top of the Johnson & Johnson page contains, among other things, a monthly price history for the stock (the vertical bars) overlaid by a solid line that we call the "cash flow" line (sometimes also called the "Value Line"). To plot the line, we multiply cash flow per share (net income plus depreciation and amortization divided by the number of shares outstanding at the end of the year) by a number (multiple) determined by our analyst. The goal is to create a "line" that most closely matches a company's stock price history and also "fits" the projected 3- to 5-year *Target Price Range.* In the case of Johnson & Johnson, the "cash flow" multiple is now 15. (The multiple can, and often does, change over time.)

The concept of a "cash flow" multiple is not too different from that for a Price/Earnings multiple (or ratio). The difference here is that instead of dividing the recent price of a stock by 12 months of earnings to create a P/E multiple, we divide the recent price by the total of 12 months of earnings plus 12 months of depreciation (and amortization, if there is any).

There is evidence that some stocks will generally trade at a price close to the "cash flow" line. In those cases when a stock is trading above the "cash flow" line, it will often move back down toward the "cash flow" line. When it is trading below, it will often do the opposite. In some cases, a stock may trade above or below the "cash flow" line for considerable periods of time.

Historical Results and Estimates

For each of the approximately 1,700 companies Value Line follows, we usually present per-share data going back 17 years in the Statistical Array in the center of each report. The historical data (item 26) appear on the left side and are presented in regular type. We also project statistical data (item 15) for the next fiscal year, as well as three to five years into the future. ***These projections are presented in bold italics.***

Now look at a list of items in the Statistical Array (items 15 and 26).

Sales per share, in the top line, is an important series. When earnings per share are depressed because of poor net profit margins, a high level of sales per share can suggest the potential for an earnings recovery. It would be disconcerting, however, if sales per share declined in tandem with earnings per share.

"Cash flow" per share (second line), as commonly used by analysts, is the sum of reported earnings plus depreciation, less any preferred dividends, calculated on a per-share basis. It is an indicator of a company's internal cash-generating ability—the amount of cash it earns to expand or replace plant and equipment, to provide working capital, to pay dividends, or to repurchase stock. Johnson & Johnson's "cash flow" per share has expanded significantly since 1988.

Earnings per share (third line) are shown by Value Line as they were reported to stockholders, excluding nonrecurring items and adjusted for any subsequent stock splits or stock dividends. According to current accounting guidelines, companies now report earnings two ways. The first is basic earnings per share, which is the earnings available to common shareholders divided by the weighted average number of shares outstanding for the period. The second is diluted earnings per share, which reflects the potential dilution that could occur if securities or other contracts to issue common stock (like options and warrants) were exercised or converted into common stock. Value Line shows only one earnings figure in our statistical presentation; that figure is clearly identified in the footnotes (item 20), and much more often than not, it is the diluted earnings figure.

For Johnson & Johnson, earnings per share have expanded consistently over the past decade and a half. As indicated in footnote (B) (*item 20*) near the bottom edge of the report page, its earnings per share are now based on diluted shares outstanding.

Dividends Declared per share (fourth line) are usually the highest, in proportion to earnings, at older and larger companies, which tend to have slower-than-average growth. Directors of growth-oriented companies more often than not prefer to pay small or "token" dividends, or none at all, so they can reinvest earnings in the business. Johnson & Johnson has regularly paid out 34% to 38% of its earnings in dividends and invested the remainder in the business. A payout of about 25% is generally typical of larger capitalization companies followed by Value Line.

Capital Spending per share (fifth line) is the amount that a company spends on new plant and equipment. It doesn't include funds used for acquisitions of other companies.

Book Value per share (sixth line) is common shareholder's equity determined on a per-share basis. It includes both tangible assets, like plant and receivables and inventories, as well as intangibles, like the value of patents or brand names, known as "goodwill." Any significant intangibles will normally be indicated in a footnote. If all assets could be liquidated at the value stated on the company's books, all liabilities such as accounts payable, taxes, and long-term debt paid, and all preferred stockholders compensated, the book value is what would be left for the common stockholders.

The number of *Common Shares Outstanding* (seventh line) is also listed in the Statistical Array. Sometimes net income rises, but earnings per share do not, because the number of shares outstanding has increased. This may happen because a company is issuing stock to pay for acquisitions or to fund internal growth. As a result, sales and profits may soar, while per-share sales and earnings lag. On the other hand, when cash-rich companies buy their own shares, earnings per share can rise even if net income is stable. Johnson & Johnson's share base has grown slightly in the past ten years.

The *Average Annual P/E Ratio* (eighth line) shows what multiple of earnings investors have been willing to pay for a stock in the past and the P/E ratio the analyst expects out 3 to 5 years. Johnson & Johnson's average annual P/E has frequently been very high in recent years, and Value Line's analyst projects that it will be above average in the years through 2007-09.

The *Relative P/E Ratio* (ninth line) shows how the stock's price-earnings ratio relates to those of all stocks in the Value Line universe. Johnson & Johnson's relative P/E of 1.09 is 9% higher than that of the typical stock. However, its relative PE has often been even higher, and the Value Line analyst thinks it will be high again in the period to 2007-09.

The *Average Annual Dividend Yield* (tenth line) is of special interest to conservative investors, many of whom are more concerned with income than with a stock's appreciation potential. Income-oriented investors should look for stocks with yields that are higher than the average shown each week in the center box of the front cover of the *Summary & Index*, but they should also look at the trend of dividends over time. Johnson & Johnson's dividend has been increased in each year shown on our page, and the analyst thinks it will continue to rise. Steady increases are very attractive for many investors. Investors should also look carefully at a company's Financial Strength to make certain that the company will be able to continue to pay the dividend. A good rule of thumb for conservative investors is to invest only in companies with Financial Strength ratings of at least B+.

Company Financial Data

The *Sales* figure (eleventh line) is the most common measure given when referring to a company's size. Johnson & Johnson's sales in 2004 are expected to be more than 2.9 times the amount recorded in 1994, a very strong performance.

The *Operating Margin* (twelfth line) indicates what percentage of sales is being converted into operating income. (Operating income is total sales minus the cost of goods sold and selling, general and administrative expenses. It is also referred to as EBITDA, or earnings before interest, taxes, depreciation, and amortization.) At Johnson & Johnson, the past decade has seen a rise in this figure, and the figure is expected to widen slightly more in the next 3 to 5 years.

Depreciation (thirteenth line) shows the amount charged against operating profits to reflect the aging of a company's plant and equipment . That number has risen quite steadily and is expected to continue to rise through 2007-09.

Net Profit (fourteenth line) is the amount the company earned after all expenses including taxes, but excluding nonrecurring gains or losses and the results of discontinued operations. Usually, the higher the net, the higher the per-share earnings. Johnson & Johnson's net profit has grown considerably since 1994, and has risen in every year.

Johnson & Johnson's *Income Tax Rate* (fifteenth line) has been in the 27% to 30% range for many years, and Value Line's analyst thinks it will stay there in the future. Income tax rates will normally remain steady unless the federal tax rate changes in the U.S. or unless a company increases or decreases the percentage of business it does overseas, where tax rates are different.

Net Profit Margin (sixteenth line) shows net income after taxes as a percentage of sales (or revenues). Here, the trend is the most important thing, with rising margins usually being favorable. It is often worthwhile to compare the net margin with the operating margin. Usually the two series move together, though not always. Depreciation charges, interest expense, income taxes, and other costs are deducted from (and other income added to) operating income in the determination of net profit. Where there is a disparity in the trends of the net and operating margins, it may be worth taking a second look. (If depreciation, interest charges, or tax rates move sharply in any direction, there will be an impact on net profits, and it would be worthwhile to try to determine why the change occurred.)

Johnson & Johnson's *Net Profit Margin* has been at record levels in recent years, and we expect the current high level to hold over the next 3 to 5 years.

Working Capital (seventeenth line), the company's current assets less current liabilities, indicates the liquid assets available for running the business on a day-to-day basis. The higher a company's sales, the more working capital it typically has and needs. But we caution that a number of large companies with steady revenue streams no longer believe large amounts of working capital are necessary. In those cases, a negative working capital may be perfectly acceptable because a company can meet normal operating expenses from consistent cash receipts.

Long-term Debt (eighteenth line) is the total debt due more than one year in the future. In the case of Johnson & Johnson, the amount is quite low relative to shareholder's equity.

Shareholders' Equity (nineteenth line), also known as net worth, is the total stockholders' interest (preferred and common) in the company after all liabilities have been deducted from the company's total assets. All intangible assets such as goodwill, patents, and, sometimes, deferred charges are included in shareholders' equity. Johnson & Johnson's equity has grown appreciably over the years, primarily from retained earnings.

Return on Total Capital (twentieth line) measures the percentage a company earns on its shareholders' equity and long-term debt obligations. When a company's return on total capital goes up, there should also be an increase in the return on shareholders' equity (see below). If not, it simply means that the company is borrowing more and paying interest, but not earning more for the stockholders on their equity in the company's assets. Unless a company can earn more than the interest cost of its debt over time, the risk of borrowing is not worthwhile.

Return on Shareholders' Equity (twenty-first line) reveals how much has been earned (in percentage terms) every year for the stockholders (common and preferred). Higher figures are usually desirable, often indicating greater productivity and efficiency. Johnson & Johnson's percent earned on net worth has been relatively high in recent years, and while it may slip in coming years, it is likely to remain above average.

Trends in both this ratio and the return on total capital—two key gauges of corporate performance—say a great deal about the skill of management.

Retained to Common Equity (twenty-second line) also known as the "plowback ratio," is net income less all dividends (common and preferred), divided by common shareholders' equity and is expressed as a percentage. It measures the extent to which a company has internally generated resources to invest for future growth. A high plowback ratio and rapidly growing book value are positive investment characteristics.

All Dividends to Net Profit, or "payout ratio," (twenty-third line) measures the proportion of a company's profits that is distributed as dividends to all shareholders—both common and preferred. Young, fast-growing firms reinvest most of their profits internally. Mature firms are better able to pay out a large share of earnings. Johnson & Johnson has been paying out 34% to 38% of its profits in the form of cash dividends. By way of comparison, the typical large company in the Value Line universe usually pays out about 25% of its profits in dividends.

1. **Value Line's Ranks**—the rank for Timeliness; the rank for Safety; the Technical rank. Beta, the stock's sensitivity to fluctuations of the market as a whole, is included in this box but is not a rank. (*See Glossary for Industry rank.*)
2. **The Legends box** contains the "cash flow" multiple, the amounts and dates of recent stock splits and an indication if options on the stock are traded.
3. **Monthly price ranges of the stock**—plotted on a ratio (logarithmic) grid to show percentage changes in true proportion. For example, a ratio chart equalizes the move of a $10 stock that rises to $11 with that of a $100 stock that rises to $110. Both have advanced 10% and over the same space on a ratio grid.
4. **The "cash flow" line**—reported earnings plus depreciation ("cash flow") multiplied by a number selected to correlate the stock's 3- to 5-year projected target price, with "cash flow" projected out to 2005.
5. **Recent price**—see page 2 of the *Summary & Index* for the date, just under "Index to Stocks."
6. **P/E ratio**—the recent price divided by the latest six months' earnings per share plus earnings estimated for the next six months.
7. **Trailing and median P/E**—the first is the recent price divided by the sum of reported earnings for the past 4 quarters; the second is an average of the price/earnings ratios over the past 10 years.
8. **Relative P/E ratio**—the stock's current P/E divided by the median P/E for all stocks under Value Line review.
9. **The stock's highest and lowest price of the year.**
10. **Dividend yield**—cash dividends estimated to be declared in the next 12 months divided by the recent price.
11. **Target Price Range**—the range in which a stock price is likely to trade in the years 2007-09. Also shown in the "Projections" box on the left.
12. **Relative Price Strength** describes the stock's past price performance relative to the Value Line Arithmetic Composite Average of approximately 1,700 stocks. (A rising line indicates the stock price has been rising more than the Value Line universe.)
13. **The % Total Return** shows the price appreciation and dividends of a stock and the Value Line Arithmetic Composite Index for the past 1, 3, and 5 years.
14. **The percent of shares traded monthly**—the number of shares traded each month as a % of the total outstanding.
15. **Statistical Array**—Value Line estimates appearing in the area on the right side are in *bold italics.*
16. **Business Data**—a brief description of the company's business and major products along, with other important data.
17. **Analyst's Commentary**—an approximately 350-word report on recent developments and prospects—issued every three months on a preset schedule.
18. **The expected date of receipt by subscribers.** *The Survey* is mailed on a schedule that aims for delivery to every subscriber on Friday afternoon.
19. **Value Line's Indexes** of Financial Strength, Stock's Price Stability, Price Growth Persistence, and Earnings Predictability. *(See Glossary for definitions.)*
20. **Footnotes** explain a number of things, such as the way earnings are reported, whether basic or diluted.
21. **Quarterly dividends paid** are actual payments. The total of dividends paid in four quarters may not equal the figure shown in the annual series on dividends declared in the Statistical Array. (Sometimes a dividend declared at the end of the year will be paid in the first quarter of the following year.)
22. **Quarterly sales** are shown on a gross basis. Quarterly earnings on a per-share basis (estimates in bold type).
23. **Annual rates of change** (on a compound per-share basis). Actual for each of the past 5 and 10 years, estimated for the next 3 to 5 years.
24. **Current position**—total current assets and total current liabilities, and their detail.
25. **The capital structure** as of the indicated recent date showing, among other things, the $ amount and % of capital in long-term debt and preferred stock. We also show the number of times that interest charges were earned.
26. **Statistical Array**—historical financial data appears in regular type.
27. **Stock purchases/sales by institutions**—the number of times institutions with more than $100 million of assets under management bought or sold stock during the past three quarters and the total number of shares held by those institutions at the end of each quarter.
28. **The record of insider decisions**—the number of times officers and directors bought or sold stock or exercised options during the past nine months.
29. **The projected stock price** in 2007-09. Also, the total expected % gain/loss before dividends and the Annual Total Return (% including dividends).

Sample Value Line Stock Page

1 2 3 4 5 6 7 8 9 10

JOHNSON & JOHNSON NYSE-JNJ | RECENT PRICE **57.66** | P/E RATIO **18.7** (Trailing: 19.5 Median: 25.0) | RELATIVE P/E RATIO **1.09** | DIV'D YLD **2.0%** | **VALUE LINE**

TIMELINESS **2** Raised 5/28/04
SAFETY **1** New 7/27/90
TECHNICAL **3** Lowered 8/6/04
BETA .65 (1.00 = Market)

High: 12.6 14.1 23.1 27.0 33.7 44.9 53.4 53.0 61.0 65.9 59.1 58.1
Low: 8.9 9.0 13.4 20.8 24.3 31.7 38.5 33.1 40.3 41.4 48.1 49.3

Target Price Range 2007 | 2008 | 2009

LEGENDS
—— 15.0 x "Cash Flow" p sh
.... Relative Price Strength
2-for-1 split 6/92
2-for-1 split 6/96
2-for-1 split 6/01
Options: Yes
Shaded area indicates recession

11

29

2007-09 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+75%)	*16%*
Low	80	(+40%)	*10%*

12

28

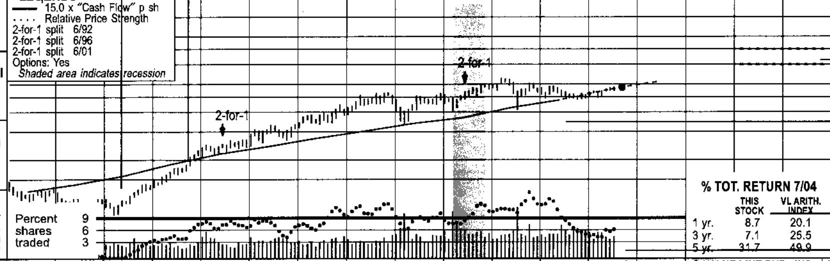
Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	1	6	2	3	2	1	1	2	0
to Sell	2	3	1	2	0	1	2	1	0

27

Institutional Decisions

	3Q2003	4Q2003	1Q2004
to Buy	607	689	698
to Sell	623	584	530
Hld's(000)	1806664	1812503	1809307



13

% TOT. RETURN 7/04

	THIS STOCK	VL ARITH. INDEX
1 yr.	8.7	20.1
3 yr.	7.1	25.5
5 yr.	31.7	49.9

14

26 15

1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	© VALUE LINE PUB., INC.	07-09
3.38	3.66	4.22	4.67	5.25	5.50	6.12	7.27	8.11	8.41	8.80	9.88	10.47	10.83	12.23	13.42	*15.60*	*16.70*	Sales per sh A	*21.40*
.51	.56	.65	.73	.85	.93	1.06	1.26	1.46	1.62	1.83	2.03	2.27	2.46	2.85	2.91	*3.75*	*4.10*	"Cash Flow" per sh	*5.50*
.36	.41	.48	.55	.62	.69	.78	.93	1.09	1.21	1.34	1.49	1.70	1.91	2.23	2.70	*3.03*	*3.30*	Earnings per sh B	*4.50*
.12	.14	.16	.19	.22	.25	.28	.32	.37	.43	.49	.55	.62	.70	.80	.93	*1.10*	*1.21*	Div'ds Decl'd per sh ■C	*1.58*
.25	.28	.31	.37	.42	.38	.36	.48	.52	.52	.54	.62	.59	.57	.71	.73	*.75*	*.80*	Cap'l Spending per sh	*1.00*
1.31	1.56	1.84	2.11	1.97	2.17	2.77	3.49	4.07	4.59	5.06	5.83	6.76	7.95	7.65	8.61	*10.75*	*12.65*	Book Value per sh D	*19.55*
2664.6	2664.4	2664.6	2665.3	2621.6	2571.9	2572.0	2590.7	2665.0	2690.3	2688.1	2779.4	2781.9	3047.2	2968.3	3119.8	*2960.0*	*2950.0*	Common Shs Outst'g E	*2900.0*
14.2	15.4	16.5	20.5	20.0	15.4	14.8	18.5	22.4	24.9	28.1	31.6	26.4	27.2	25.9	21.9	*Bold figures are*		Avg Ann'l P/E Ratio	*20.0*
1.18	1.17	1.23	1.31	1.21	.91	.97	1.24	1.40	1.44	1.46	1.80	1.72	1.39	1.41	1.27	*Value Line*		Relative P/E Ratio	*1.35*
2.4%	2.2%	2.1%	1.7%	1.8%	2.4%	2.4%	1.9%	1.5%	1.4%	1.3%	1.2%	1.4%	1.3%	1.4%	1.8%	*estimates*		Avg Ann'l Div'd Yield	*1.8%*
						15734	18842	21620	22629	23657	27471	29139	33004	36298	41862	*46165*	*49200*	Sales ($mill) A	*62000*
						22.4%	23.2%	24.6%	25.1%	26.6%	27.0%	27.4%	28.8%	31.2%	30.5%	*31.5%*	*32.0%*	Operating Margin	*33.5%*
						724.0	857.0	1009.0	1067.0	1246.0	1444.0	1515.0	1605.0	1662.0	1869.0	*2050*	*2180*	Depreciation ($mill)	*2725*
						2006.0	2403.0	2887.0	3303.0	3677.6	4209.0	4800.0	5885.0	6810.8	7197.0	*9090*	*9865*	Net Profit ($mill)	*13185*
						25.2%	27.6%	28.4%	27.8%	27.1%	27.5%	27.5%	28.2%	29.0%	30.2%	*28.5%*	*28.0%*	Income Tax Rate	*27.5%*
						12.7%	12.8%	13.4%	14.6%	15.5%	15.3%	16.5%	17.8%	18.8%	17.2%	*19.7%*	*20.1%*	Net Profit Margin	*21.3%*
						2414.0	3550.0	4186.0	5280.0	2970.0	5746.0	8310.0	10429	7817.0	9547.0	*14500*	*16780*	Working Cap'l ($mill)	*24500*
						2199.0	2107.0	1410.0	1126.0	1269.0	2450.0	2037.0	2217.0	2022.0	2955.0	*2500*	*2000*	Long-Term Debt ($mill)	*1500*
						7122.0	9045.0	10836	12359	13590	16213	18808	24233	22697	26869	*31750*	*37350*	Shr. Equity ($mill)	*56760*
						22.3%	22.3%	24.2%	24.9%	25.2%	22.9%	23.3%	22.5%	27.8%	24.4%	*26.0%*	*24.0%*	Return on Total Cap'l	*22.0%*
						28.2%	26.6%	26.6%	26.7%	27.1%	26.0%	25.5%	24.3%	30.0%	26.8%	*28.5%*	*26.5%*	Return on Shr. Equity	*23.0%*
						18.0%	17.4%	17.7%	17.5%	17.5%	16.8%	16.4%	15.8%	19.5%	16.6%	*18.0%*	*14.0%*	Retained to Com Eq	*15.0%*
						36%	34%	34%	34%	35%	35%	36%	35%	35%	38%	*36%*	*37%*	All Div'ds to Net Prof	*35%*

25

CAPITAL STRUCTURE as of 6/27/04
Total Debt $3,453 mill. **Due in 5 Yrs** *$500.0* mill.
LT Debt $2,962 mill. **LT Interest** $174.0 mill. (9% of Cap'l)
Leases, Uncapitalized Annual rentals $143.0 mill.

Pension Assets-12/02 $6,050 mill. **Oblig.** $7,680 mill.
Pfd Stock None

Common Stock 2,968,107,066 shs. **as of 7/25/04**

MARKET CAP: $171 billion (Large Cap)

24

CURRENT POSITION ($MILL.)	2002	2003	6/27/04
Cash Assets	7475	9523	10786
Receivables	5399	6574	7142
Inventory (FIFO)	3303	3588	3528
Other	3089	3310	3201
Current Assets	19266	22995	24657
Accts Payable	3621	4996	3829
Debt Due	2117	1363	491
Other	5711	7089	7742
Current Liab.	11449	13448	12062

23

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '01-'03 to '07-'09
Sales	9.0%	7.5%	*10.0%*
"Cash Flow"	12.5%	11.0%	*12.5%*
Earnings	13.5%	12.5%	*12.0%*
Dividends	13.5%	13.5%	*12.0%*
Book Value	14.5%	12.0%	*16.0%*

22

Fiscal Year Ends	QUARTERLY SALES ($ mill.) A Mar.Per	Jun.Per	Sep.Per	Dec.Per	Full Fiscal Year
2001	8021	8342	8238	8403	33004
2002	8743	9073	9079	9403	36298
2003	9831	10322	10455	11254	41862
2004	11559	11484	*11250*	*11872*	*46165*
2005	*12150*	*12250*	*12000*	*12800*	*49200*

Fiscal Year Ends	EARNINGS PER SHARE AB Mar.Per	Jun.Per	Sep.Per	Dec.Per	Full Fiscal Year
2001	.50	.51	.50	.40	1.91
2002	.59	.60	.60	.44	2.23
2003	.69	.70	.69	.62	2.70
2004	.83	.82	*.76*	*.62*	*3.03*
2005	*.88*	*.89*	*.83*	*.70*	*3.30*

21

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2000	.14	.16	.16	.16	.62
2001	.16	.18	.18	.18	.70
2002	.18	.205	.205	.205	.80
2003	.205	.24	.24	.24	.93
2004	.24	.285			

16

BUSINESS: Johnson & Johnson manufactures and sells health care products. Major lines by segment: Consumer (baby care, non-prescription drugs, sanitary protection, and skin care), Medical Device & Diag. (wound closures, minimally invasive surgical instruments, diagnostics, orthopedics, and contact lenses), and Pharmaceutical (contraceptives, psychiatric, anti-infective, and dermatological drugs). 2003 sales (operating income) by segment: Pharm., 47% (60%); Med. Device & Diag., 35% (28%); Consumer, 18% (12%). Int'l business, 40% of '03 sales; R&D, 11%. Has 109,100 empl.; 164,200 stockholders. Off./dir. own less than 1% (3/04 Proxy). Chrmn. & CEO: William Weldon. Inc.: NJ. Addr.: One J&J Plaza, New Brunswick, NJ 08933. Tel.: 732-524-0400. Web: www.jnj.com.

Johnson & Johnson topped expectations in 2004's initial half, and we've raised our earnings estimate for the year. In the March quarter, the company beat our $0.82 bottom-line estimate by a penny, with net rising 20%. It exceeded our figure by $0.02 (and consensus by $0.03) in the second period, posting a 17% year-over-year increase. Revenues were up 11.3% in the most recent quarter, 8.5% on a constant currency basis. Significantly, too, sales growth was solid across all three major businesses, with pharmaceuticals, medical devices & diagnostics, and consumer expanding by 11.1% (to $5.4 billion), 11.8% ($4.1 billion), and 10.0% ($2.0 billion), respectively. An enriched sales mix, meantime, along with cost-cutting initiatives, added 1.2 percentage points to the gross margin. In view of both the outperformance and the receding prospect of generic rivals for *Duragesic*, we've upped (by $0.06) our estimate for 2004 to $3.03, in line with management's guidance.

The bottom-line advance will likely continue to decelerate, though, slowing into single-digit territory in 2005. Sales of *Procrit/Eprex*, J&J's best-seller, are under substantial competitive and pricing pressures, as underscored by a 14% (or $137 million) drop in the June quarter. Top-line contributions from another key growth driver, *Cypher* (drug eluting stent), is also being squeezed mightily, by Boston Scientific's *Taxus*, which was launched in March. And, early next year, *Duragesic*, which we estimate will add about $2 billion to 2004 sales, will undoubtedly face stiff competition from generics. J&J has a decent new-drug pipeline, but we think the share-net advance will be about 9% in 2005, compared with 12% this year and 21% in 2003. 17

These top-quality shares still deserve consideration. The healthcare products giant has almost $11 billion in cash. As well, it generates some $6 billion annually in free cash flow. Thus, management has ample financial flexibility with which to transfigure the company's growth profile. 18 Major acquisitions and/or stock repurchases are clearly viable options. J&J stock is timely for the year ahead. Moreover, it also offers good risk-adjusted, 3- to 5-year total-return potential.

George Rho *September 3, 2004*

20

(A) Year ends on last Sunday of December. **(B)** Primary earnings through '96, diluted thereafter. Excludes nonrecurring gains/(losses): '90, 5¢; '92, 23¢; '98, 22¢; '99, 2¢; '01, (7¢); '02, (7¢); '03: Q2, (30¢). May not sum to total due to rounding. Next earnings report due mid-Nov. **(C)** Dividends historically paid mid: March, June, Sept., Dec. ■Div'd reinvestment plan available. **(D)** Incl. intang.: In '03, $12.2 billion, $3.91/sh. **(E)** In mill., adj. for stock splits.

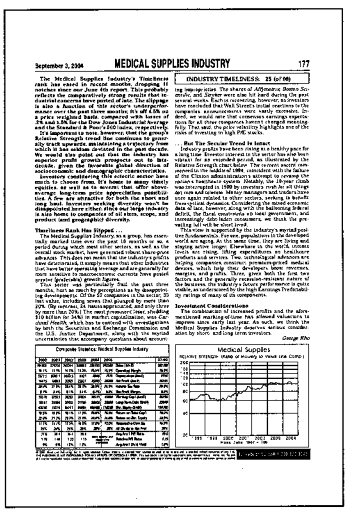
Company's Financial Strength	A++
Stock's Price Stability	95
Price Growth Persistence	90
Earnings Predictability	100

19

CHAPTER

6

THE VALUE LINE INDUSTRY REPORT



September 3, 2004 MEDICAL SUPPLIES INDUSTRY 177

All the company reports in *The Value Line Investment Survey* are grouped by industry, and at the front of each industry group is a one- or two-page Industry Report.

The information contained in each Industry Report may differ considerably from one industry to another, but there is a general format we follow.

The number of industries followed in *The Value Line Investment Survey* is constantly changing. As companies drop out, usually because of mergers or acquisitions, we may discontinue an industry. On the other hand, as new industries develop, we add them. Some we have added in the past two years are Biotechnology, Human Resources, Entertainment Technology, and Coal.

Analytical Commentary

Much of each page contains analytical commentary. The text in each report is written by a Value Line security analyst, who normally also follows a number (sometimes as many as 10 or 12) of the companies in the industry.

The text normally includes comments about important developments in the industry and the impact those developments have been having on the companies. It also usually includes the analyst's projections about the immediate and longer-term prospects for the industry. We always recommend that you read this report to get an idea of just what an analyst thinks about an industry.

Composite Statistics

In the lower left corner of most reports is a table of Composite Statistics for an industry. The statistics are compiled from the data on the individual companies; the individual data headings are the same as those on the company pages.

Composite Statistics: Medical Supplies Industry

2000	2001	2002	2003	2004	2005		07-09
164858	201055	248344	268645	**290135**	**312500**	Sales ($mill)	**382700**
16.1%	15.1%	14.5%	15.2%	**15.5%**	**15.5%**	Operating Margin	**15.5%**
5577.5	6350.1	6330.5	6621	**6940**	**7175**	Depreciation ($mill)	**8150**
14415	16869	20095	22627	**25295**	**28200**	Net Profit ($mill)	**36355**
29.6%	27.8%	29.4%	29.5%	**29.5%**	**29.5%**	Income Tax Rate	**29.5%**
8.7%	8.4%	8.1%	8.4%	**8.7%**	**9.0%**	Net Profit Margin	**9.5%**
30578	32333	38233	37624	**39275**	**42000**	Working Cap'l ($mill)	**48750**
18597	25586	28450	27065	**26000**	**25000**	Long-Term Debt ($mill)	**22000**
63058	79376	86741	95895	**106480**	**118285**	Shr. Equity ($mill)	**154700**
18.5%	16.8%	18.1%	17.8%	**19.0%**	**19.5%**	Return on Total Cap'l	**19.0%**
22.9%	21.3%	23.2%	22.9%	**24.0%**	**24.0%**	Return on Shr. Equity	**23.5%**
17.1%	15.7%	17.5%	16.8%	**17.0%**	**17.0%**	Retained to Com Eq	**16.5%**
25%	26%	25%	25%	**28%**	**28%**	All Div'ds to Net Prof	**30%**
27.6	28.4	24.4	20.8	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	**19.0**
1.79	1.46	1.33	1.15			Relative P/E Ratio	**1.25**
.9%	.9%	1.0%	1.2%			Avg Ann'l Div'd Yield	**1.6%**

These statistics have two primary uses. First, they help an investor to examine trends in an industry. Second, they provide a benchmark for comparisons. An investor can look at the statistics on an individual company page and compare them with those of the industry to see how a company stacks up with its industry. He/she can also compare one industry with another.

Industry Trends

When purchasing a stock in a company, an investor should also know something about the industry in which a company is operating. Some important questions are:

- Is the industry growing?
- Are the industry's operating and profit margins growing or at least remaining steady?
- Are the industry's returns on total capital and shareholders' equity growing or at least remaining steady?

The answer to these questions can be found in the Composite Statistics table. In most cases, if an industry's trends are favorable, the operating conditions for the companies in that industry will also be favorable. If the industry trends are negative, the opposite may be true.

Company/Industry Comparisons

When you are investing in a company, you should also know how that company is performing relative to its industry. A company's size and operating performance are both very important, and you should study them by looking at our individual company pages. However, you should also know if a company is well run. Some questions an investor should ask are:

- How do a company's operating margins compare with the industry's operating margins?
- How do a company's net profit margins compare with the industry's margins?
- Are a company's returns on total capital and on shareholders' equity greater or smaller than those of the industry?

If a company's margins and returns are above average, the company is probably efficiently run. If the margins and returns are lower than most firms in the industry, the company is probably not being run as well as it could be.

WARNING! Many industries are dominated by one or two companies. When that is the case, company/industry comparisons may not be very useful. Examples here are Anheuser-Busch, which accounts for more than half the sales in our Alcoholic Beverage Industry, and Dow Chemical and Dupont, which together have more 80% of the sales of our Basic Chemical Industry. ***Be careful when making company/industry comparisons to make certain the comparisons are meaningful.***

Industry Timeliness

At the top right of each report, we publish an INDUSTRY TIMELINESS rank. These go from 1 (highest) to 98 (lowest).

The Industry Timeliness ranks are calculated by averaging the Timeliness ranks of each of the stocks in a particular industry. If an industry has a large number of stocks ranked 1, the Industry Timeliness rank is likely to be high. If an industry has a large number of stocks ranked 5, the Industry rank is likely to be low.

The Industry ranks are updated weekly and published on the front and inside pages of the *Summary & Index*. You should always look in the *Summary & Index* to make certain you have the most recent numbers.

Relative Strength Chart

In the lower right corner of most reports is a relative strength chart going back for as many as seven years. Relative strength compares the price of a stock over time with the price of the stock market over the same time. (In this case, we use the Value Line Composite Index of approximately 1,700 stocks to represent the market.) When the relative strength line is rising, it means that the stocks in an industry are stronger than the broad market. When the line is falling, the stocks in an industry are weaker than the broad market.

CHAPTER

7

ANSWERS TO FREQUENTLY ASKED QUESTIONS

*Long-term subscribers to **The Value Line Investment Survey** are often well aware of the basic tenets of investing and the many ways information can be used in **The Value Line Investment Survey**. However, they and many newer readers often have questions about material in the publication. Below are answers to those questions we receive most frequently.*

TIMELINESS RANKS

How do you determine the *Timeliness* rank, and what makes it change?

TIMELINESS	**2**	Raised 5/28/04
SAFETY	**1**	New 7/27/90
TECHNICAL	3	Lowered 8/6/04
BETA .65 (1.00 = Market)		

Ranks Box
(Also see item 1, on page 21)

Value Line's *Timeliness Ranking System* ranks all of the approximately 1,700 stocks in our universe for relative price performance in the coming six to 12 months. At any one time, 100 stocks are ranked 1; 300 are ranked 2; approximately 900 are ranked 3; 300 are ranked 4; and 100 are ranked 5. In simple terms, *Timeliness* ranks [which go from 1 (Highest) to 5 (Lowest)] are determined by a company's earnings growth and its stock's price performance over a 10 year period. A rank may change under three circumstances. The first is the release of a company's earnings report. A company that reports earnings that are good relative to those of other companies and good relative to the numbers we had expected may have its stock move up in rank, while a company reporting poor earnings could see its stock's rank drop.

A change in the price of a stock can also cause a stock's rank to change. A change in price carries less weight than a change in earnings, but it is still an important determinant. Generally speaking, strong relative price performance is a plus, while negative relative price performance (relative to all other approximately 1,700 stocks) is a minus.

And finally, there is the "Dynamism of the Ranking System." This phrase means that a stock's rank can change even if a company's earnings and stock price remain the same. That's because a fixed number of stocks is always ranked 1, 2, etc. Every time one stock's *Timeliness* rank moves up or down, another's must also change. As an example, let's suppose one company reports unusually good earnings, causing its stock's *Timeliness* rank to rise from 2 to 1. Since there can be only 100 stocks ranked 1, some other stock must fall to a rank of 2, even though there has been no change in its earnings or price.

Can you tell me where a particular stock ranks within its class (a high 1, a low 1, etc.)?

We do not disclose this information. However, we do list the date when a rank last changed and what the direction of the change was. Next to the *Timeliness* rank on each company page you can see when the last change occurred and whether it was raised or lowered. Changes are also indicated each week in the *Summary & Index* by an arrow next to *Timeliness* ranks.

I think that *Value Line* should change a certain stock's rank. Will you do it?

We appreciate your interest, but all ranks are generated by computer driven criteria and historical data. Value Line methodology keeps our System objective and unbiased, because the same criteria apply to all stocks.

Would you tell me the formula you use to calculate ranks?

The details of the formula are proprietary. The components of the *Timeliness Ranking System,* as mentioned earlier, include the long-term trend of earnings and stock prices, recent company earnings and stock price performance, and a comparison of the latest quarterly earnings with those that had been expected. (Better than expected earnings are normally positive, less than expected earnings, negative.) We cannot be more specific than that.

Why do stocks with *Timeliness* ranks of 1 or 2 sometimes have below-average, long-term appreciation potential, and vice versa?

Probably the most important thing for all readers to know is that **the time horizons for *Timeliness* ranks and for 3- to 5-year *Projections* are very different**. Our *Timeliness* ranks are for the relative performance of stocks over the coming six to 12 months. Our forecast for long-term price potential is for 3 to 5 years. Because of the very different time periods, our forecasts for the two periods can be very different.

To provide a more specific answer, stocks ranked 1 or 2 for *Timeliness* often have been moving higher and often sell at high price/earnings ratios. While we think these stocks will continue to outperform other stocks in the Value Line universe during the next six to 12 months, it is unrealistic to think a stock's price will keep moving up forever. At some point, earnings growth is likely to slow, at least somewhat, and our analysts try to be as realistic as possible in calculating the 3- to 5-year projections. If earnings growth slows in the future, a stock's price/earnings ratio is likely to narrow, limiting the potential for appreciation in the stock's price.

Why do some stocks not have a *Timeliness* rank?

Our computer-generated *Timeliness* ranks require at least two years of income statement and stock price history. If a stock has been trading for less than two years, possibly because a company is relatively new or because there was a major spinoff or acquisition, we are unable to assign a rank to it. We also suspend Timeliness ranks for unusual developments such as a merger offer or a bankruptcy filing.

TECHNICAL RANK

What exactly is the Technical rank?

The Technical rank uses a stock's price performance over the past year to attempt to predict short-term (three to six month) future returns. Each stock in our 1,700-company universe is ranked in relation to all others on a scale of 1 (Highest) to 5 (Lowest). There are no other factors incorporated into the model. While our Technical rank does contribute to investment decisions, we would like to stress that our primary investment advice is based on our successful time-proven *Timeliness Ranking System.* The Technical rank is best used as a secondary investment criterion.

EARNINGS

Why does *Value Line* sometimes show different share earnings than those in a company's annual report, or in The Wall Street Journal, or in a brokerage house report?

We each calculate earnings differently. In particular, *Value Line* excludes what we consider to be unusual or one-time gains or charges in order to show what we consider to be "normal" earnings.

Company earnings often contain one-time non-recurring or unusual items, such as expenses related to the early retirement of debt, a change in accounting principles, restructuring charges, or a gain or loss on the sale of assets. In order to make a reasonable comparison of core operating results from one year to the next—or from one company to another—it is necessary to exclude these items from reported earnings. Some items are relatively easy to take out because they are explicitly shown in the company's income statement and footnotes. Others, however, must be estimated by our analysts. Any unusual adjustments to reported earnings will be disclosed in the footnotes of each Value Line report.

OPERATING MARGIN

What is an operating margin?

The operating margin shows operating income (earnings before the deduction of depreciation, amortization, interest, and income taxes) as a percentage of sales or revenues. Operating income is sometimes referred to as EBITDA.

PRICE/EARNINGS RATIO

Why does the Value Line price/earnings ratio often differ from that in The Wall Street Journal or brokerage reports?

All price/earnings ratios are calculated by dividing the recent stock price by 12 months of earnings. The different ratios occur because we each use different 12-months earnings figures. Newspapers use 12-months trailing (i.e., reported) earnings. *Value Line* uses a total of the past six months of trailing earnings and the next six months of estimated earnings. (In our view, this is the best method since it incorporates both recent history and a near-term forecast.) Your broker is likely to use a calendar year's earnings. While we think our method is best, none is wrong. Just be sure that when you are comparing two companies' P/E ratios, you are using the same methods.

For additional information on P/E ratios, please turn to page 15.

ABBREVIATIONS

I have trouble understanding some of your abbreviations. Can you help me?

Yes. Most of the frequently used abbreviations are included in the Glossary at the end of this guide.

SELECTION & OPINION MODEL PORTFOLIOS

How are stocks chosen for the Model Portfolios I, II and III in *Selection & Opinion*?

Each portfolio is dedicated to a different investment objective. To guard against near-term underperformance, none of the portfolios can hold a stock that is ranked below 3 (Average) for *Timeliness. Timeliness* ranks range from 1 (Highest) to 5 (Lowest). To make it more attractive and useful to conservative investors, Portfolio II must hold stocks that are ranked at least 3 (Average) for *Safety.*

Portfolio I, Stocks with Above-Average Year-Ahead Price Potential, is built on Value Line's well-respected *Timeliness* Ranking System. It is primarily suitable for investors who wish to take more risk in hopes of greater returns than might be afforded in Portfolios II or III. To qualify for purchase, stocks have to be ranked 1 (Highest) for *Timeliness.* To reduce portfolio turnover (and recognizing the fact that many good growth stocks go up and down in price along the way), a stock that drops a rank in *Timeliness* to 2 (Above Average) may remain in the portfolio, assuming that the company's longer-term fundamentals remain sound. A stock that drops to 3 (Average) for *Timeliness* must be sold. We attempt to diversify the holdings as much as possible, but note that the *Timeliness Ranking System* tends to favor high earnings growth and more volatile issues that may cluster in a few industries.

Portfolio II, Stocks for Income and Potential Price Appreciation, attempts to combine our *Timeliness Ranking System* with an investment objective for above-average income. This portfolio is primarily suitable for more conservative investors. To qualify for purchase, a stock's yield (the estimated annual dividend for the next 12 months divided by the recent stock price) must be higher than the median yield for all approximately 1,700 stocks Value Line follows. The median is shown on the cover of the *Summary & Index* each week. The stock must also have a *Timeliness* rank of at least 3. The higher-than-average yields provide support to the shares in down markets. This portfolio tends to be less volatile because the companies, as a whole, are more likely to be mature and predictable.

Portfolio III, Stocks with Long-Term Price Growth Potential, is based on the fundamental research of our staff of research analysts. This portfolio is suitable for investors with a 3- to 5-year horizon; in terms of risk, it falls somewhere between Portfolios I and II. This portfolio tends to be the most flexible, allowing purchases of a broader array of companies. It is constructed under the principles of modern portfolio theory, which state that the risk of a portfolio should be viewed within the context of a portfolio as a whole, rather than judging the portfolio according to the average rankings of individual securities it holds. To that end, this portfolio is generally well diversified, comprising stocks in a variety of different non-related industries.

The Selected Investments section of *Selection & Opinion* has three portfolios. Why isn't there a "Conservative" portfolio?

Portfolio II, Stocks for Income and Potential Price Appreciation, is the one we would recommend for "conservative" investors. A key criterion for this portfolio is that the stocks have above-average dividend yields. These attractive yields lend support to stock prices when the market is declining. This portfolio usually also has slightly lower-than-market risk (volatility) as measured by the average beta of the portfolios.

How have the Model Portfolios done?

We publish the record quarterly in *Selection & Opinion*, usually three or four weeks after the end of a quarter. We also publish them on our Web site in the section called "About Value Line."

FINANCIAL STRENGTH

What goes into the Financial Strength rating for each individual company?

Company's Financial Strength	A++
Stock's Price Stability	95
Price Growth Persistence	90
Earnings Predictability	100

Financial/Stock Price Data

(Also see item 19, on page 21)

Our Financial Strength ratings take into account a lot of the same information used by the major credit rating agencies. Our analysis focuses on net income, cash flow, the amount of debt outstanding, and the outlook for profits. Other factors also enter into the equation. For example, a company that faces the loss of patent protection on a key product might face a downgrade. The ratings range from A++ (Highest) to C (Lowest), in nine steps, based on the judgment of our senior staff members.

A STOCK'S 3- TO 5-YEAR PRICE PROJECTIONS

How are a stock's 3- to 5-year share-price projections derived?

Our analysts have developed comprehensive spreadsheet models that take into account the current economic climate and a company's operating fundamentals, including recent management initiatives, the actions of the competition, and many other relevant factors for each company. These models are used to develop our earnings and other financial projections for the coming 3 to 5 years.

The *Target Price Range* is calculated by multiplying a company's estimated earnings per share for the period out 3 to 5 years (in the far right hand column of the statistical array) by the stock's projected average annual price/earnings ratio for the same period and then developing a range showing the likely high and low price. The width of the band of the share-price projections varies, depending on the *Safety* rank of the company. Riskier stocks have a wider band, safer stocks a narrow band.

STOCK DECLINES

I bought a stock based on your advice, but it went down. What happened?

As you undoubtedly know, our *Timeliness Ranking System* has worked extremely well over time. Not all stocks do as we forecast, though, and we have never suggested that they will. What we have strongly recommended is that you diversify your portfolio by purchasing at least six stocks in at least six or more industries. That way, you will protect yourself from unexpected changes in the price of any one stock or any one industry. Also keep in mind that the *Value Line Ranking System* is relative. In declining markets, group 1 and 2 stocks have historically declined less than the general market. On the other hand, stocks ranked 1 and 2 have outperformed the market during periods when stock prices were rising.

SPEAKING TO ANALYSTS

I would like to speak to the Analyst who wrote a report.

Unfortunately, this isn't practical. Our staff of approximately 70 analysts has been hired and trained to analyze stocks and write commentaries for *The Value Line Investment Survey* and, to be fair to all subscribers, they do not have time to provide personalized advice or information.

PRETAX INCOME

Where can I find pretax income on a Value Line page?

You can't. We do, however, show net profit after taxes (usually line 14 in the Statistical Array) and the effective tax rate (usually line 15). You can calculate pretax income by dividing net profit by: 1 minus the tax rate. Example: If net profit was \$100 million and the tax rate was 36%, pretax profit would be \$156.25 million.

$$\frac{\$100,000,000}{1.00 - .36} = \$156,250,000$$

ERRORS IN REPORTS

What should I do if I find an error in a report?

If you think you have found an error in any of our publications, we would very much like to hear from you so that we can correct the mistake. Please write or call us. If you call, let the operator know that you want to report an apparent error, and he/she will connect you with an administrative assistant in the Research Department. Please address your written comments to the office of the Research Director, or e-mail us at VLIS@valueline.com.

If you believe you have found an error in an historical price or per share data item, please read on:

We actually receive very few complaints about our data. Most of those that we do get relate to historical prices and per share data, and the fact is that our stock prices, earnings, and other data are usually correct. When there appears to be a difference in stock prices or earnings per share, it is usually because of a stock split or a stock dividend. Value Line (and everyone else) retroactively adjusts historical stock prices and share data for stock splits and dividends. Splits and dividends of 10% or more are shown in the *Legends* box in the upper left hand corner of the price chart. Splits of less than 10% are shown in the footnotes.

INTERNET (WEB) SITE

Does Value Line have a Web site?

Yes, we do. Our address is *www.valueline.com*. The Web site includes useful features for today's informed investor.

The Web site is designed to help keep you informed about the stock market and the stocks you are interested in. There is a section where you can get recent stock prices and news on companies you are interested in, and another where you can set up your own portfolios. Three times each day we provide both written and video commentary from our economist and senior portfolio managers. Each afternoon we provide the latest analysis from our security analysts about selective stocks in the news that day. We also archive all issues of *The Value Line Investment Survey* published in the past three months.

To access some of this data, you must be a subscriber. To enter the "subscriber-only" section, you must enter your user code (your subscriber number on the label of your weekly envelopes) and password ("stocks").

COMPANY COVERAGE

Does a company pay to be included in *The Value Line Investment Survey*?

No. Value Line is not compensated by the companies under our review. This allows us to be totally objective when we analyze companies in *The Value Line Investment Survey.*

Does the roster of stocks covered by *Value Line* change?

Yes. Vacancies constantly occur within our approximately 1,700 stock universe. Sometimes a company's earnings will deteriorate to such a degree that we believe investors have lost interest. If that happens, we will discontinue coverage. More frequently, companies leave our universe when they are acquired by or merged with another firm. Acquired or merged companies will be replaced by others. In choosing replacements, we try to select actively traded stocks with broad investor interest.

Why isn't ABC, Inc., a large well known company, included?

We do try to include companies with actively traded stocks, which have broad public interest. If ABC fits in this category, we will, in all likelihood, provide coverage in the future.

GROWTH RATES

How are the growth rates calculated in the Annual Rates of change box?

We use a compound annual rate that reflects the annual change for various items over the entire period being computed. All rates of change are computed from the average figure for a past 3-year period to an average for a future 3-year period. For more details, see page 14.

ANNUAL RATES of change (per sh)	**Past 10 Yrs.**	**Past 5 Yrs.**	**Est'd '01-'03 to '07-'09**
Sales	9.0%	7.5%	*10.0%*
"Cash Flow"	12.5%	11.0%	*12.5%*
Earnings	13.5%	12.5%	*12.0%*
Dividends	13.5%	13.5%	*12.0%*
Book Value	14.5%	12.0%	*16.0%*

Annual Rates Box

(Also see item 23, on page 21)

GLOSSARY

Aaa Corporate Bond Rate—the average yield on corporate bonds rated Aaa by Moody's Investors Service. Bonds that are rated Aaa are judged to be of the best quality compared to all other corporate bonds.

After-Tax Corporate Profits—*see Corporate Profits.*

AFUDC—*see Allowance for Funds Used During Construction.*

Allowance for Funds Used During Construction (Electric Utility Industries)—a non cash credit to income consisting of equity and debt components. This non cash income results from construction work in progress and is expected to be converted into cash income at a future date.

American Depositary Receipts (ADRs)—since most other nations do not allow stock certificates to leave the country, a foreign company will arrange for a trustee (typically a large bank) to issue ADRs (sometimes called American Depositary Shares, or ADSs) representing the actual, or underlying, shares. Each ADR is equivalent to a specified number of shares (the ratio is shown in a footnote on the Value Line page).

American Stock Exchange Composite—a market-capitalization weighted index of the prices of the stocks traded on the American Stock Exchange.

Amortization—an accounting method that reduces the value of an asset on a regular basis over time.

Analyst's Commentary—an approximate 350-word report on each company page in *Ratings & Reports* on recent developments and prospects—issued every three months on a preset schedule.

Annual Change D-J Industrials (Investment Companies)—the yearly change from year end to year end in the Dow Jones Industrial Average, expressed as a percentage.

Annual Change in Net Asset Value (Investment Companies)—the change in percentage terms of the net asset value per share at the end of any given year from what it was at the end of the preceding year, adjusted for any capital gains distributions made during the year.

Annual Rates of Change (Per Share)—compound yearly rates of change of per-share sales, cash flow, earnings, dividends, and book value, or other industry-specific, per-share figures, over the past 10 years and five years and estimated for the coming three to five years. Historical rates of change are computed from the average figures for a past three-year period to the most recent actual three-year period. Forecasted rates of change are computed from the average figure for the most recent three-year period to an average for a future three-year period. If data for a three-year period are not available, a two- or one-year base may be used.

Annual Total Return—a compound yearly return to shareholders that includes both stock price appreciation and dividend returns.

Annuity—a form of contract sold by life insurance companies that guarantees a fixed or variable payment at some future time.

Arithmetic Average—a simple mean. Items to be averaged are added and their sum is divided by the number of items. The result is an arithmetic, or simple, average (or mean).

Asset Quality (Bank and Thrift Industries)—an indicator of problem loans and other assets relative to total assets. A bank with good asset quality, for example, has a lower percentage of problem loans than the average bank.

Asset Value Per Share Year End (Investment Companies)—total common equity at year end, with securities valued at market rather than cost, divided by the number of shares outstanding at year end.

Assets—for a corporation, the total of current assets (normally cash and short-term investments, inventories, and receivables) and long-term assets (normally including property and equipment and good will).

Assets Year End (Investment Companies)—total investment company assets at market value, including stocks, bonds, government securities, and cash, at year end.

Available Seat Miles (ASM) (Air Transport Industry)—a measure of the airline seating capacity available for sale. Each ASM is one seat flown one mile.

Average Annual Dividend Yield—dividends declared per share for a year divided by the average annual price of the stock in the same year, expressed as a percentage.

Average Annual P/E ratio— is calculated by dividing the average price for a year with the actual reported earnings for that year and is shown in the Statistical Array.

Average Annual Price Earnings (P/E) Ratio—the average price of the stock for the year divided by earnings per share (excluding nonrecurring items, as determined by Value Line) reported by the company for the year. In the case of fiscal-year companies, all data are for the fiscal year. (*See also Price/Earnings ratio.)*

Average Interest Rate Paid (Financial Services Industries)—the interest paid during the year divided by the average debt outstanding.

Average Price for the Year—the sum of the 52 Wednesday closing prices for a stock for the year divided by 52.

Backlog—orders for goods and services that have been received but not yet delivered or rendered.

Balance Sheet—financial statement that lists the assets, debts, and owner's investment as of a specific date.

Basic Earnings Per Share—net income divided by the weighted average number of common shares outstanding during a period. (This calculation is required by the Financial Accounting Standards Board for all years ending after December 15, 1997.)

Basis Point—in the context of discussions on interest rates, one basis point equals one-hundredth of one percentage point.

Beta—a relative measure of the historical sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Index. A Beta of 1.50 indicates a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Index. The "Beta coefficient" is derived from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are adjusted for their long-term tendency to converge toward 1.00.

Bond—a long-term debt instrument, characterized typically by fixed, semiannual interest payments and a specified maturity date.

Book Value Per Share—net worth (including intangible assets), less preferred stock at liquidating or redemption value, divided by common shares outstanding.

Business Data—a section on a Value Line company report that describes the company's most important products, lists large shareholders, and includes the company's address, telephone number, and Internet address.

Capacity at Peak (Electric Utility Industry)—a utility's generating capability plus purchases from other utilities less sales to other utilities.

Capacity Utilization—the ratio of actual production levels to maximum possible production levels, expressed as a percentage. The Federal Reserve Board publishes capacity utilization figures monthly for both the overall economy and individual industries.

Capital Funds (REIT Industry)—stockholders' equity (net worth) plus subordinated debt.

Capital Gains Per Share After Tax (Real Estate Industry)—profits derived net of income taxes on the sale of property (either land or buildings) during the year, expressed in terms of the number of common shares outstanding at yearend.

Capital Spending Per Share—the outlays for plant and equipment for the year expressed on a per-share basis. Excludes funds spent for acquisitions.

Capital Structure—a balance sheet item defined by Value Line as the total of a company's long-term debt, preferred stock at liquidation or redemption value, and its shareholders' equity.

Capitalization — see **Market Capitalization.**

Cash Assets—the sum of cash on hand plus short-term securities, such as Treasury bills, that can readily be converted into cash.

"Cash Flow"—the total of net income plus non-cash charges (depreciation, amortization, and depletion) minus preferred dividends (if any). See Free Cash Flow.

"Cash Flow" Line—also known as the "Value Line." See page 17 for more information.

"Cash Flow" Per Share—net profit plus non cash charges (depreciation, depletion, and amortization), less preferred dividends (if any), divided by common shares outstanding at year end.

CD—abbreviation for Certificate of Deposit. See also Time Deposits.

Certificate of Deposit—*see* ***Time Deposits.***

Closed-End Investment Company (or Fund)—a company or fund that has a relatively fixed number of shares (hence the term "closed-end") that are bought or sold through broker/dealers on the stock exchange. In contrast, an open-end (or mutual) fund stands ready (continually) to redeem shares for cash or issue new shares for cash and, hence, deals directly with its investors.

Combined Ratio (Insurance [Property/Casualty] Industry)—the percentage of losses to premiums earned plus the percentage of expenses to premiums written. The break-even point is 100%; in other words, a combined ratio of less than 100% represents an underwriting profit and a combined ratio of more than 100% represents an underwriting loss.

Common Equity Ratio—shareholder's equity divided by total capital (i.e., long-term debt, preferred equity, and common equity).

Common Shares Outstanding—the number of shares of common stock actually outstanding at the end of a company's accounting year. This total excludes any shares held in the company's treasury. The figures for common shares outstanding in previous years are fully adjusted for all subsequent stock splits and stock dividends.

Common Stock to Surplus (Insurance Industries)—the market value of the common stock held in the insurance company's investment portfolio divided by statutory net worth.

Compound Growth—the annual rate of growth of an investment when dividends or interest are reinvested.

Consumer Price Index—a Labor Department index, published monthly, designed to reflect changes in the cost of living. Housing, food, beverage, and transportation costs account for about 80% of the value of the index, which is a measure of inflation at the consumer level.

Conversion Price—the effective price paid for common stock when the stock is obtained by converting either convertible preferred stock or convertible bonds or debentures. For example, if a $1,000 bond is convertible into 20 shares of stock, the conversion price is $50, that is, $1,000 divided by 20.

Convertible Debentures—long-term debt instruments, not secured with collateral, that may be converted into a specified number of shares of common stock.

Convertible Preferred Stock—preferred stock that may be converted into a specified number of shares of common stock.

Corporate Profits—the aggregate of all profits for U.S. corporations reported by the Commerce Department as part of the domestic income and product (GDP) accounts. Reported both on a pretax and aftertax basis. They are somewhat different from profits reported to shareholders and profits reported for tax purposes.

Current Assets—assets that may reasonably be expected to be converted into cash, sold, or consumed during the normal operating cycle of a business, usually 12 months or less. Current assets usually include cash, receivables, and inventories.

Current Liabilities—financial obligations that will have to be satisfied within the next 12 months. Current liabilities include accounts payable, taxes, wage accruals, and total short-term debt, or Debt Due (the sum of notes payable and the portion of long-term debt maturing in the operating year).

Current Position—the components of a company's working capital are presented in this table in Value Line reports on industrial companies. The difference between current assets and current liabilities is known as Working Capital.

Current Ratio—the sum of current assets divided by the sum of current liabilities.

Cyclical Stock—stocks of companies whose earnings tend to fluctuate with the economy (the opposite of a growth stock, which is defined below).

d—a deficit, or a loss.

Debenture—a long-term debt instrument that is usually not secured by collateral.

Debt—see Total Debt, Long-Term Debt, Debt Due, and Total Debt Due in 5 Years.

Debt Due—the sum of bank notes and other notes payable in 12 months (or less) and that portion of long-term debt due within 12 months. See also Total Debt Due in 5 Years.

Demand Deposits (Bank Industries)—deposits that a depositor may withdraw from his account at any time.

Depletion—an accounting method that allows companies extracting oil, gas, coal, or other minerals to gradually reduce the value of these natural resources.

Deposits (Bank Industries)—total savings (time and demand deposits) entrusted to a bank.

Deposits (Thrift Industry)—funds that have been entrusted to a thrift.

Depreciation—an amount charged against operating profits to reflect the aging of plant and equipment owned by a company.

Diluted Earnings Per Share—net income (with certain possible adjustments) divided by the weighted average number of shares outstanding during a period, assuming any securities or other contracts to issue common stock (including options and warrants) were exercised or converted into common stock. (This calculation is required by the Financial Accounting Standards Board for all years ending after December 15, 1997.)

Dilution—the reduction in earnings associated with the hypothetical conversion of convertible securities into common stock. Also, in the context of a discussion of a merger or acquisition, the reduction in share earnings estimated to occur as a result of the merger or acquisition.

Discount From or Premium Over Net Asset Value (Investment Companies)—the difference between the net asset value and market price, expressed as a percentage of net asset value. If the price exceeds the net asset value, the percentage of the excess or premium is shown with a plus sign.

Disposable Income—a Commerce Department figure published monthly that reflects personal income less income taxes and other taxes. Conceptually, the statistic is designed to reflect funds available for consumers to spend or save.

Dividend—a payout to shareholders determined by a Board of Directors.

Dividend Yield—the year-ahead estimated dividend yield (shown in the top right-hand corner of the Value Line page) is the estimated total of cash dividends to be declared over the next 12 months, divided by the recent price of the stock.

Dividends Declared Per Share—the common dividends per share declared (but not necessarily paid) during the company's operating, fiscal year (displayed within the Statistical Array of the Value Line page). See also Dividends Paid Per Share.

Dividends Paid Per Share—the common dividends per share paid (but not necessarily declared) during the calendar year (indicated in the quarterly dividend box in the bottom left corner of the Value Line page). See also Dividends Declared Per Share.

Dow Jones Industrial Average—a price-weighted average of 30 of the largest U.S. industrial companies, published by Dow Jones & Co.

Dow Jones Transportation Average—a price-weighted average of 20 of the largest U.S. transportation companies, published by Dow Jones & Co.

Dow Jones Utility Average—a price-weighted average of 15 of the largest U.S. utility companies, published by Dow Jones & Co.

Downstream (Petroleum [Integrated] Industry)—the refining and marketing operations of an integrated oil company, as opposed to exploration and production activities (which are referred to as upstream operations).

Durable Goods—products used by consumers or businesses that are expected to last three or more years. These goods tend to be big-ticket items (for example, automobiles and washing machines). Durable goods sales are generally interest rate sensitive and correlate with the overall level of economic activity.

Dynamism—*see page 24.*

Earned Surplus—*see* ***Retained Earnings.***

Earnings—see also Net Profit. A company's total profit before nonrecurring gains or losses, but after all other expenses.

Earnings Per Share—net profits attributable to each common share as originally reported by the company, but adjusted for all subsequent stock splits and stock dividends; may be based on weighted average shares outstanding (Basic EPS) or weighted average shares including all shares reserved for conversion of convertible securities (Diluted EPS). Annual and quarterly earnings per share figures on the Value Line page exclude nonrecurring or one-time gains and losses, which are noted in the footnotes.

Earnings Per Share (Bank Industries)—net profit after taxes, expressed on a per-share basis as reported by the company. Includes investment securities gains and losses after 1982.

Earnings Per Share Sensitivity to Change in Loss Ratio (Insurance [Property/Casualty] Industry)—the degree to which earnings per share will be affected by a one percentage point change in the insurance company's loss ratio.

Earnings Predictability—a measure of the reliability of an earnings forecast. Predictability is based upon the stability of year-to-year comparisons, with recent years being weighted more heavily that earlier ones. The most reliable forecasts tend to be those with the highest rating (100); the least reliable, the lowest (5). The earnings stability is derived from the standard deviation of percentage changes in quarterly earnings over an eight-year period. Special adjustments are made for comparisons around zero and from plus to minus.

Earnings Surprise—company earnings reports that are significantly better or worse than were forecast.

Equally Weighted Average—a stock price index that gives equal weight to each stock regardless of its price or market capitalization. The Value Line indexes are equally weighted averages.

Equity—ownership interest held by shareholders in a corporation (essentially the same as stock).

Equity Offering—the selling of stock by a corporation.

Ex-Dividend Date—the date by which an investor must have purchased a stock in order to receive announced dividends or stock distributions.

Expense Ratio (Insurance [Property/Casualty] Industry)—see Percent Expense to Premiums Written.

Expense Ratio (REIT Industry)—expenses other than interest, expressed as a percentage of the average assets.

Expenses/Assets (Investment Companies)—operating expenses expressed as a percentage of the investment company's total assets at yearend.

Exports—the sale of goods and services from one country to another. U.S. exports of goods and services are reported by the Commerce Department in its Gross Domestic Product (GDP) reports.

Federal Funds—a market among commercial banks in which banks that need a short-term loan in order to meet regulatory reserve requirements are able to borrow from banks with excess funds. The Federal Funds rate is the interest rate charged on such loans.

Federal Reserve Board—the governing body of the Federal Reserve System, which regulates certain banks and is charged with setting national monetary policy.

FHLB Advances (Thrift Industry)—funds borrowed from the regional Federal Home Loan Bank.

Financial Strength Rating—a relative measure of financial strength of the companies reviewed by Value Line. The relative ratings range from A++ (strongest) down to C (weakest), in nine steps.

Financial Times-Stock Exchange 100 (FT-SE 100)—a stock price index made up of 100 of the largest stocks traded on the London Stock Exchange. The index is published by The Financial Times, a London-based financial newspaper.

Finding Cost (Natural Gas [Diversified] and Petroleum Industries)—the amount of money spent per barrel to increase proved reserves through acquisitions, discovery, or enhanced recovery.

Fixed-charge Coverage (Electric Utility Industry)—pretax operating income after depreciation but before other income, interest charges, and Allowance for Funds Used During Construction (AFUDC), divided by long-term plus short-term interest plus twice the preferred dividend. Used as a measure of financial strength for an electric utility. A fixed charge coverage of 100 means that the operating income equals fixed expenses. A figure above 100 means that operating income exceeds fixed expenses, and vice versa.

Free Cash Flow—net income plus depreciation minus the total of dividends, capital expenditures, required debt repayments, and any other scheduled cash outlays.

Full Cost Accounting (Canadian Energy, Natural Gas Diversified, and Petroleum Industries)—a method of accounting under which all costs related to the exploration and development of oil and gas reserves are immediately expensed (a less conservative method than Successful Efforts Accounting).

Fully Diluted Earnings Per Share—earnings per share assuming conversion of all convertible securities plus the exercise of all warrants and options. Similar to Diluted Earnings, which replaced Fully Diluted EPS for all years after December 15, 1997.

Funds Borrowed (Bank Industries)—Federal Funds (free reserves borrowed from other banks), securities sold under Repurchase Agreements ("repos"), commercial paper sold by bank holding companies and non bank subsidiaries, and any other non deposit sources of short-term funds.

GAAP—abbreviation for the Generally Accepted Accounting Principles used by U.S. companies and determined by the Financial Accounting Standards Board (FASB), a private, industry-sponsored organization.

General and Administrative Expenses—expenses such as salaries, rents, advertising, and public relations.

Geometric Average—a geometric average is the nth root of the product of n terms. If n = 3, the geometric average of the three numbers would be the cube (or third) root of the product of the three numbers.

Goodwill—see intangibles.

Government Securities (Bank Industries)—fixed-income debt obligations of the U.S. Government and federal agencies.

Gross Billings (Advertising Industry)—the aggregate outlays for advertising paid by clients to the media. Billings generally serve as a basis for agency commissions.

Gross Dividend Declared per ADR (American Depositary Receipts)—dividends per ADR declared (but not necessarily paid) during the company's fiscal year before any withholding taxes. For companies based in the United Kingdom, dividends declared are net of the Advance Corporation Tax.

Gross Equipment (Air Transport Industry)—the total of all flight equipment, ground stations, and other property, and all equipment (including property under capital lease) at original cost as reported by the airline company. Does not include advance payments for new equipment.

Gross Income (Financial Services Industry)—the total of interest on receivables, discounts, commissions, service charges, and other revenues.

Gross Income (REIT and Thrift Industries)—all income earned in normal operations excluding nonrecurring items such as gains from property sales.

Gross Income to Interest Ratio (Financial Services Industry)—gross income divided by total interest paid.

Gross Loans (Bank Industries)—total loans outstanding before deductions for loan-loss reserves and unearned income.

Gross Margin – Gross Profit as a % of Sales.

Gross Portfolio Yield (Investment Companies)—gross annual income (before any expenses) divided by total assets at yearend, expressed as a percentage.

Gross Profit (Industrial and Retail Industries) – The income remaining after subtracting the cost of the goods sold. Gross Profit is income before other expenses such as general, selling, and administrative costs, interest, depreciation, and taxes.

Growth Stock—stocks of companies whose earnings grow consistently over time reflecting the fact that such companies have limited sensitivity to the country's economy as it moves up and down (the opposite of a cyclical stock, which is defined above).

Holding Company—a business that confines its activities to owning stock in and supervising the management of other companies.

Housing Starts—the number of single- and multi-family units for which construction has begun. Published by the Commerce Department.

Imports—a country's purchases of goods or services from other countries. U.S. imports of goods and services are reported by the Commerce Department when it releases the Gross Domestic Product (GDP) report.

Income Dividends Per Share (Investment Companies)—dividends declared from net investment income on a per-share basis.

Income Statement—a financial report that lists revenues, expenses, and net income throughout a given period.

Income Stocks—stocks with higher-than-average dividend yields. (Often, but not always, stocks with dividends that are considered likely to be maintained or raised.)

Income Taxes—the total of all foreign and domestic (federal, state and city) taxes charged against income.

Income Tax Rate—total income taxes as a % of pretax income.

Industrial Production—a Federal Reserve index, published monthly, of the output of the nation's factories, mines, and utilities.

Industry Timeliness Rank—the relative *Timeliness* rank of an industry, updated weekly in the *Summary & Index* and calculated by averaging the *Timeliness* ranks of each of the stocks assigned a *Timeliness* rank in the industry. Industries with high *Timeliness* ranks are those with large percentages of stocks that also have high *Timeliness* ranks. The rank of each industry is listed on the front cover of *Summary & Index*, next to the name of the industry.

Initial Public Offering—a corporation's first equity offering to the public.

Initial Unemployment Insurance Claims—a weekly Labor Department compilation of new unemployment claims based on data from each of the States in the Union and Washington, D.C.

Insider Decisions—the number of decisions to buy or sell a company's shares made by officers and directors and shown by month for a nine-month period. This table is shown on the left side of the price chart on the *Ratings & Reports* page. (The source of this information is Vickers Stock Research Corp.)

Institutional Decisions—the number of decisions reported by investment managers having equity assets under management of $100 million or more to buy or sell a company's shares. This table appears on the left side of the price chart on the Value Line page. (The source of this information is Vickers Stock Research Corp.)

Insurance in Force (Insurance Industries)—the aggregate face amount of all life insurance policies outstanding.

Intangibles—assets such as goodwill (the excess of cost over net assets of companies acquired by purchase), patents, trademarks, unamortized debt discounts, and deferred charges. This figure, if it is material, is footnoted on the Value Line page.

Intangibles Per Share—intangible assets divided by the number of common shares at year end.

Interest—payment for the use of borrowed money. Many companies have both interest charges (for long- and short-term funds they have borrowed) and interest income (for money they have invested, usually in short-term, interest-bearing investments).

Interest Cost to Gross Income (Thrift Industry)—interest expenses for the year, expressed as a percentage of gross income.

Inventories—raw materials, work in progress, and finished products. LIFO (last-in, first-out) accounting minimizes illusory, but taxable, inventory profits in periods of rising prices because high-cost materials are expensed against income first. Under FIFO (first-in, first-out) accounting, the reverse is true. Average cost (middle-in, middle-out) is a compromise between LIFO and FIFO.

Inventory Investment—the change in inventories valued at average prices for the period, as published by the Commerce Department in its periodic Gross Domestic Product reports.

Inventory-to-Sales-Ratio—a ratio of inventories to sales, expressed as a percentage. An excessively high ratio may indicate that businesses have too much inventory on hand and are about to cut back production in order to reduce inventories. A decline in production would slow economic growth.

Inventory Turnover—sales divided by year-end inventory. A measure of the efficiency of inventory management.

Investment Company (or Fund)—a company or fund that invests in other companies (usually through the purchase of equity or debt securities) or invests in commodities or real property, etc., or any combination of the above.

Investment Income (Insurance Industry)—dividends, interest, and rents received on investments and any other investment income less the expenses of the investment department.

Investment Income Per Share (Insurance Industry)—dividends, interest, and rents received on investments less the expenses of the investment department, divided by the number of common shares outstanding at year end.

Large Cap — a market capitalization (stock price times shares outstanding) of more than $5 billion.

Leading Economic Indicators—a monthly Commerce Department index designed to gauge future economic activity.

Leases—contractual rentals of plant and equipment. Must be "capitalized" when most of the benefits and obligations of ownership are transferred to the lessee. Capitalizing leases increases long-term debt and gross plant, and depreciation and interest are charged to profits. Uncapitalized-lease accounting enhances the balance sheet, since the financial obligation is not shown.

Legends Box—the box at the top of the Price Chart in each full-page report in *The Value Line Investment Survey.* This box is labeled LEGENDS and includes the specific "Cash Flow" per share multiple that will be plotted on the Price Chart and lists stock splits. It also identifies the "Cash Flow" and Relative Price Strength lines that are plotted on the Price Chart

Leveraged Buyout—a corporate takeover, often led by members of management, in which funds are borrowed against company assets in order to pay off existing shareholders. As a result, a publicly held company becomes a highly leveraged, privately held company.

Life Premium Income (Insurance Industries)—funds received from policyholders in exchange for promises to make future payments upon (1) death or at a specific date or dates under various forms of life insurance and annuity contracts and/or (2) disability under accident and health contracts.

Load Factor (Air Transport Industry)—the percentage of total airline seating capacity that is actually sold and utilized. It is computed by dividing revenue passenger miles flown by available seat miles flown in scheduled service.

Load Factor (Electric Utility Industry)—the ratio of the average output in kilowatts supplied during a designated period to the maximum output occurring in that period.

Loan Loss Experience (Bank and Thrift Industries)—net loan charge-offs divided by average loans outstanding in a given period.

Loan Loss Provision (Bank and Thrift Industries)—funds set aside each quarter in order to cover future possible losses on loans that are not repaid. This figure appears on the bank's income statement.

Loan Loss Reserve (Bank Industries)—reserves set aside at a point in time in order to cover future possible loan losses. This figure appears on the bank's balance sheet.

Long-Term Debt—the portion of borrowings (including bank notes, debentures, and capitalized leases) that will be due not in the current 12 months, but in future operating years.

Long-Term Interest Earned—pretax income plus long-term interest expense (including capitalized interest) divided by long-term interest. *See **Total Interest Coverage.***

Market Capitalization (Market Cap)—the market value of all common shares outstanding for a company, calculated by multiplying the recent price of a stock by the number of common shares outstanding. Large Cap stocks have market values of more than $5 billion. Mid Cap stocks have market values of from $1 billion to $5 billion. Small Cap stocks have market values of less than $1 billion. (When there are multiple classes of common stock, which often sell at different prices, the number of shares of each class is multiplied by the applicable price.)

Market-Capitalization Weighted Average—a stock price index weighted by the value of all shares outstanding for each stock. In such an index, large market capitalization stocks get proportionately more weight than small stocks.

Median—the middle value in an ordered series of numbers. As an example, if you ranked a number of stocks in order based on stock price from high to low, the stock price in the middle would be the median.

Median Price Earnings (P/E) Ratio (as shown on the top of a Value Line company report)—is the average annual P/E ratio of a stock over the past 10 years, with certain statistical adjustments made for unusually low or high ratios.

Merchandise Trade Balance—the difference between U.S. exports of goods and U.S. imports of goods. Published monthly by the Commerce Department.

Mid Cap — a market capitalization (stock price times shares outstanding) of from $1 billion to $5 billion.

Money Supply—Federal Reserve measures of money outstanding. The Federal Reserve is able to influence increases or decreases in the size of the money supply. If money supply grows significantly faster than overall economic growth for an extended period of time, higher rates of inflation often follow. If money supply grows too slowly, economic growth is inhibited.

NA—not available; information that was not available when the report went to press.

NASDAQ Composite—a market-capitalization weighted average of approximately 5,000 stocks traded electronically in the NASDAQ market.

Net Asset Value (Investment Companies)—the market value of a company's assets less any liabilities divided by the number of shares outstanding.

Net Income—see Net Profit.

Net Interest Income (Bank and Thrift Industries)—the dollar amount of interest received on loans and other investments, less the dollar amount of interest paid on deposits and other borrowings.

Net Interest Margin (Bank Industries)—the difference between interest rates earned (on loans and other earning assets) and interest rates paid (on deposits and other sources of funds) divided by total value of earning assets.

Net Loan Losses (Bank Industries)—loans written off during a period net of recoveries on loans previously written off. Also referred to as net loan charge-offs and net loan write-offs.

Net Profit (or Income)—a company's total profit before nonrecurring gains or losses, but after all other expenses.

Net Profit Margin—net income before nonrecurring gains and losses as a percentage of sales or revenues.

Net Revenues (Advertising Industry)—total commissions and fees received by the agency.

Net Sales—gross volume less returns, discounts, and allowances.

Net Working Capital—working capital less long-term debt, preferred stock at liquidating value, deferred taxes, minority interests, other long-term liabilities, and intangible assets. Occasionally the phrase is used in a less strict sense to mean working capital less long-term debt. See Working Capital.

Net Worth—all the assets shown on the balance sheet, including any intangible assets (i.e., goodwill, debt discount, deferred charges) less current liabilities, long-term debt, and all other noncurrent liabilities. In other words, the sum of common plus preferred stockholders' equity. Generally referred to as shareholders' equity.

New Loan Volume (Thrift Industry)—the total of loans originated plus loans purchased in a given period by a thrift.

New York Stock Exchange Composite—a market-capitalization weighted average of all the common stocks traded on the New York Stock Exchange.

Nikkei Stock Average—an index of 225 Japanese stocks. A barometer of the Japanese stock market.

NMF—not meaningful. Used when a number or ratio is so large or small that it is not meaningful. For example, a price/earnings ratio of 100 would probably not be meaningful because earnings in a particular period were unusually depressed.

Non-Financial Domestic Debt—the sum of U.S. consumer, business, and government borrowings outstanding.

Non-interest Expense (Bank Industries)—expenses other than interest and loan loss provisions, such as wages and overhead.

Non-interest Income (Bank Industries)—income other than interest income, such as trust fees, other fee income, and gains on securities transactions.

Non-performing Assets (Bank and Thrift Industries)—generally includes loans that are not providing, or are not expected to provide, interest income at the contractual rate. Also includes foreclosed properties.

Nonrecurring Items—various unusual gains or losses excluded from reported earnings by Value Line analysts in order to reflect income from ongoing operations. Nonrecurring items are footnoted by year on the Value Line page.

$100 DJI Grew To (Investment Companies)—the amount to which a $100 investment (divided equally) in each of the 30 Dow Jones Industrial Stocks would have grown from year end 1960 (or year in which the company began operations).

$100 Net Assets Grew To (Investment Companies)—the amount to which $100 invested in the net assets of a closed-end fund would have grown from year-end 1960 (or after the first year of the company's operation), assuming all capital gains distributions had been reinvested in additional shares.

Operating Earnings—earnings (profits) left after subtracting the cost of goods sold and marketing, general, and administrative costs from sales. Sometimes referred to as EBITDA (earnings before interest, taxes, depreciation, and amortization).

Operating Income—see Operating Earnings.

Operating Margin—operating earnings as a percentage of sales.

Operating Profit—see Operating Earnings.

Option—a contract that gives a buyer the right to buy or sell 100 shares of stock within a certain period of time and at a pre-established price. A call option gives an investor the right to buy 100 shares of stock at a specified price, while a put option allows him to sell 100 shares.

Output Per Hour (Nonfarm)—a Labor Department index of what U.S. non-agricultural workers produce, on average, in an hour. An increase in this index over time is an indicator of productivity gains.

Par Value—the nominal or face value of a stock or bond.

Passenger Yield (Air Transport Industry)—the average revenue per mile paid by each passenger, computed by dividing passenger revenues by revenue passenger miles.

Payout Ratio—see Percent All Dividends to Net-Profit.

P/E Ratio—the price of the stock divided by earnings for a 12-month period. See Average Annual Price-Earnings (P/E) Ratio, Current Price-Earnings (P/E) Ratio, Trailing Price-Earnings (P/E) Ratio, and Median Price-Earnings (P/E) Ratio.

Peak Load (Electric Utility Industries)—the greatest demand for power during a specified period of time.

Pension Liability—the total of all unfunded, vested pension benefits that have been accrued.

Percent All Dividends to Net Profit—the sum of all cash dividends (common and preferred) declared, but not necessarily yet paid, for a company's operating or fiscal year, divided by net profit for that year, expressed as a percentage. Also known as the payout ratio.

Percent Commissions (Securities Brokerage Industry)—income received for execution of trades in commodities, listed securities, NASDAQ transactions, and sales for mutual fund shares as a percentage of total revenues.

Percent Common Stocks (Investment Companies)—the value of common stocks held as a percentage of total assets at year end.

Percent Earned Common Equity—net profit less preferred dividends divided by common equity (i.e., net worth less preferred equity at liquidation or redemption value), expressed as a percentage. See Percent Earned Total Capital.

Percent Earned Shareholders' Equity—net profit divided by net worth, expressed as a percentage. See Percent Earned Total Capital.

Percent Earned Net Worth (REIT Industry)—net profit divided by average net worth for the year, expressed as a percentage.

Percent Earned Total Assets (Bank and Thrift Industries)—net profit divided by total reported assets, expressed as a percentage.

Percent Earned Total Capital—net profit plus one half the interest charges on long-term debt divided by total capital (i.e., long-term debt plus net worth), expressed as a percentage.

Percent Earned Total Capital (REIT Industry)—net profit plus total interest expense (i.e., the sum of short- and long-term interest outlays) divided by the average total capital (i.e., average total debt plus average net worth), expressed as a percentage. Should be compared to Percent Earned Net Worth to determine the impact of leverage (i.e., use of borrowed capital) to enhance the return to stockholders.

Percent Expense to Premiums Written (Insurance [Property/Casualty] Industry)—underwriting expense (commissions and general and administrative costs) divided by net premiums written less dividends to policyholders, expressed as a percentage. Also called the Expense Ratio.

Percent General & Administrative Expense to Gross Income (Thrift Industry)—expenses such as salaries, rents, and advertising and public relations costs divided by gross income for the year, expressed as a percentage.

Percent Interest Cost to Gross Income (Thrift Industry)—interest expenses for the year divided by gross income for the year expressed as a percentage.

Percent Interest Income (Securities Brokerage)—interest derived from funds loaned to customers' margin accounts plus interest on government and corporate securities held in the company's account, expressed as a percentage of total revenues.

Percent Investment Banking (Securities Brokerage Industry)—fees received for private placements, venture capital financing, real estate activity, mergers and acquisitions, exchange and tender offers, consulting, underwriting, and syndication participation, expressed as a percentage of total revenues.

Percent Investment Income to Total Investments (Insurance [Property/Casualty] Industry)—investment income less associated expense divided by total investments, expressed as a percentage.

Percent Losses to Premiums Earned (Insurance [Property/Casualty] Industry)—losses and loss expenses divided by premiums earned, expressed as a percentage. Also called the Loss Ratio.

Percent Price to Book Value (Insurance Industries)—the average price for the year divided by book value per share, expressed as a percentage.

Percent Principal Transactions (Securities Brokerage Industry)—trading and securities transactions for the firm's own account (e.g., block positioning, market making, and government, municipal, and corporate bond trading out of the company's inventory), expressed as a percentage of total revenues.

Percent Problem Assets to Mortgage Loans—total assets at year end that are problems.

Percent Short-Term Debt to Total Debt (Financial Services Industry)—all debt due in the next 12 months divided by total short-and long-term debt at year-end, expressed as a percentage.

Per Share Basis—total Sales, "Cash Flow," Earnings, or Dividends, and other data divided by the number of shares outstanding. Earnings and dividends are almost always described on a per share basis for ease of understanding.

Personal Consumption Expenditures—consumer spending reported monthly by the Commerce Department. Also included in the Gross Domestic Product (GDP) reports.

Personal Income—consumer income reported monthly by the Commerce Department. Also included in the Gross Domestic Product (GDP) reports.

Plant Age—an estimate derived by dividing accumulated depreciation at the most recent year end by the depreciation allowance in the most recent year.

Plowback Ratio—*see* ***Retained to Common Equity.***

Policyholders' Dividends (Life Insurance Industries)—refunds to the policyholder of part of the premium paid on participation life insurance policies, reflecting the difference between the premium charged and actual mortality experience.

Policyholders' Surplus (Life Insurance Industries)—book value as determined using statutory accounting techniques. Statutory accounting, unlike generally accepted accounting principles (GAAP), does not permit deferral of policy acquisition costs.

Preference Stock—see Preferred Stock.

Preferred Stock—a security that represents an ownership interest in a corporation and gives its owner a prior claim over common stockholders with regard to dividend payments and any distribution of assets should the firm be liquidated. Preferred stock normally is entitled to dividend payments at a specified rate. These dividends must be paid in full before the payment of a common stock dividend. May or may not have seniority over preference stock (which is akin to preferred stock), depending on state regulations.

Preferred Stock Ratio—preferred stock at liquidation or redemption value divided by total capital (i.e., the sum of long-term debt, preferred equity, and common equity), expressed as a percentage.

Premium Income Per Share (Insurance Industries)—income to the insurance company consisting of payments made by life, accident and health, disability, and property/casualty insurance policyholders as provided for under the terms of their insurance contracts, divided by the number of common shares outstanding.

Premium Over Book (REIT Industry)—the percentage by which the average annual stock price exceeds the average annual book value per share. If the stock sells at a discount from book value, the percentage of that year is preceded by a minus sign.

Premium Over Net Asset Value (Investment Companies)—*see* ***Discount From Net Asset Value.***

Premium Written to Surplus (Insurance [Property Casualty] Industry)—the total premium received for policies sold during the year divided by legally defined net worth.

Premiums Earned (Insurance Industry)—premiums received in advance for insurance protection that will remain in force for a year or more. Premiums accrue to revenues (i.e., are earned) only in proportion to the actual time elapsed under the policy relative to the entire policy term.

Premiums Written Per Share (Insurance [Property/Casualty] Industry)—the total premiums received from property/casualty insurance policyholders for policies sold during the year divided by the number of common shares outstanding.

Present Value—the amount that, if paid today, would be the equivalent of a future payment, or series of future payments, under specified investment assumptions. If, for example, funds can be invested today to yield 10% annually, a payment of $100 to be made one year hence has a present value of $90.91; that is, $100 divided by 1.10.

Pretax Corporate Profits—*see* ***Corporate Profits.***

Pretax Margin—profits before federal, state, and foreign income taxes as a percentage of sales or revenues.

Price Chart—a graphic historical presentation of the movement of a stock and, often, additional information. The price chart that appears on each Value Line page includes monthly stock price ranges (small vertical lines), a cash flow line (a solid line with projections shown as dashes), and a relative-strength price line (a series of dots).

Price Earnings Ratio—Probably the most widely used measure of stock valuation. Value Line shows a variety of P/E ratios on every company page, as discussed below:

The P/E ratio on the very top of the Value Line page (item 6 on page 21). This is calculated by dividing the recent price of the stock by the total of the last six months earnings and the next six months of estimated earnings.

The *Relative P/E ratio.* This compares the P/E of one stock with the median of estimated P/E ratios of all stocks under Value Line review. A relative P/E of more than 1 indicates that a stock's P/E ratio is currently higher than that of the Value Line universe; a P/E of less than 1 indicates that this stock's P/E is less than the Value Line average.

A *Trailing P/E ratio.* This is calculated by dividing the recent price of the stock by the past 12 months of actual (reported) earnings. This is the figure shown in most newspapers.

A *Median P/E ratio.* This is the average annual P/E ratio of a stock over the past 10 years, with certain statistical adjustments made for unusually low or high ratios.

The *Average Annual P/E ratio.* This is calculated by dividing the average price for a year with the actual reported earnings for that year and is shown in the Statistical Array.

The *Average Relative Annual P/E ratio.* This is calculated by dividing the average annual P/E of a stock with the average annual P/E of all stocks under Value Line review.

Price Growth Persistence—a measurement of the historic tendency of a stock to show persistent price growth compared to the average stock. Value Line Persistence ratings range from 100 (highest) to 5 (lowest).

Price-Weighted Average—a stock price average that gives proportionately more weight to stocks with high share prices than it does to stocks with low prices. The Dow Jones Averages are price-weighted.

Primary Earnings Per Share—earnings per share calculated on the assumption of the conversion of certain senior securities (those of the company deemed, according to an accounting formula, to be common stock equivalents—that is, likely to trade like common shares) into common stock. This calculation has not been used since 1997.

Prime Rate—the base lending rate reported by the largest commercial banks in the nation.

Problem Assets (Thrift Industry)—delinquent loans, loans past due 90 days or more, and foreclosed real estate.

Producer Price Index (PPI)—Labor Department price indexes of goods categorized by industry and by stage of processing. Widely watched among them are the raw materials, intermediate goods, and finished goods indexes. A measure of inflation.

Projections Box—a box appearing in the upper left corner of a Value Line stock page. It includes the absolute price gain expected for the next 3 to 5 years as well as the compound annual return (appreciation plus dividends) during the same period.

Proved Reserves (Petroleum and Natural Gas /Diversified Industries)—quantities of natural resources that engineering estimates indicate with reasonable certainty are economically recoverable using present technology.

Quarterly Earnings—box appearing at the lower left hand corner of *The Value Line Investment Survey* page (directly below the quarterly sales box) in which five years of actual and estimated earnings are listed for each of the four quarters of each listed year.

Quarterly Sales—box appearing at the lower left hand corner of *The Value Line Investment Survey* page in which five years of actual and estimated sales are listed for each of the four quarters of each listed year.

Rate Base (Electric Utility Industry)—usually the net original cost of plant and equipment; in some instances including an allowance for cash, working capital, materials, and supplies.

Real—in the context of economic activity, a measure that excludes the effects of inflation. Real Gross National Product, for example, is a measure of the nation's output of goods and services, adjusted for inflation.

Real Estate Investment Trust (REIT)—a financial intermediary that invests its equity capital and debt in income-producing real estate and mortgages. Under legislation passed in 1961, REITs were granted conduit tax treatment (the same as that permitted mutual funds) under which the part of earnings which flows through to shareholders in the form of dividends is exempt from Federal income taxes at the trust (or corporate) level, provided several conditions are met. Among the conditions for qualification as a REIT under the Internal Revenue Code: At least 95% of otherwise taxable income must be distributed to shareholders in the calendar year earned, and specified percentages of both investments and gross income must be related to real estate.

Realized Gain or Loss—profit or loss on the sale of an asset.

Receivables—the value of goods and services sold and shipped to customers, for which the company has yet to be paid.

Receivables (Financial Services Industry)—the amount of money owed to finance companies by customers at year-end, net of unearned discount (the charges to the borrower) and loss reserves.

Relative Price-Earnings (P/E) Ratio—the stock's current P/E divided by the median P/E for all stocks under Value Line review. (*See also Price Earnings Ratio.*)

Relative Strength Price Line—a representation shown in the price chart on each Value Line page as a series of dots. The line compares the price of a stock with the price of an index (in this case the Value Line Arithmetic Composite) over time. When the line is rising, the stock is acting better than the broad index. When it is falling, the stock is acting worse than the index.

Reserve Life (Natural Gas [Diversified] and Petroleum Industries)—a company's reserves of oil, gas, or other natural resources divided by annual production.

Reserve Replacement Ratio (Natural Gas and Petroleum Industries)—the ratio of reserve additions to production. Reserve replacement is calculated by summing the total reserves added over a five-year period. The ratio is calculated by dividing replacement by production over the same period.

Retail Sales—a monthly measure of all U.S. retail activity, published by the Commerce Department.

Retained Earnings—net profit for the year, less all common and preferred dividends, when relating to the income account. With respect to the balance sheet or common equity, it is the sum of net profit in all years of the company's existence less all dividends (common and preferred) ever paid. In this case, also known as earnings retained or earned surplus.

Retained to Common Equity—net profit less all common and preferred dividends divided by common equity including intangible assets, expressed as a percentage. Also known as the Plowback Ratio.

Return on Shareholders' Equity—annual net profit divided by year-end shareholders' equity

Return on Total Capital—annual net profit plus 1/2 of annual long-term interest divided by the total of shareholders' equity and long-term debt

Revenue—see Sales.

Revenue Passenger Miles (Air Transport Industry)—a measure of airline traffic. Each revenue passenger mile represents one revenue-paying passenger flown one mile.

Revenues (Banks)—this figure has not been used by most banks in the past. However, the combination of net interest income and non-interest income will provide investors with a close approximation.

Revenues (Electric Utility, Natural Gas [Distribution], Telecommunications Industries)—the amounts billed for services rendered.

Revenues (Real Estate Industry)—the total of rental, construction, and interest income and property sales.

Revenues Per Share—gross revenues for the year divided by the number of common shares outstanding at year end.

Safety Rank—a measurement of potential risk associated with individual common stocks. The Safety Rank is computed by averaging two other Value Line indexes—the Price Stability Index and the Financial Strength Rating. Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit their purchases to equities ranked 1 (Highest) and 2 (Above Average) for Safety.

Sales—gross volume less returns, discounts, and allowances; net sales.

Sales Per Share—net sales divided by the number of common shares outstanding at year-end.

Savings Deposits Per Share (Thrift Industry)—total savings deposits at year-end divided by the number of common shares outstanding at yearend.

Savings Rate—the personal savings rate, expressed as a percentage of consumer income, published monthly by the Commerce Department.

Seasonally Adjusted—a statistical method of adjusting economic data for seasonal differences in economic activity. For example, monthly retail sales are adjusted for the surge of buying that takes place during the end-of-year holiday season.

Shareholders' Equity—a balance sheet item showing a company's net worth. Represents the sum of common and preferred equity including redeemable preferred. Also includes intangibles.

Short-Term Debt—all debt due in the next 12 months and, therefore, considered a current liability. Same as Debt Due. See Total Debt.

Small Cap—a market capitalization (stock price times shares outstanding) of less than $1 billion.

Spot Market—a market in which commodities are purchased or sold and delivered quickly, that is, on the spot.

Standard Deviation—a statistical measure of volatility.

Standard & Poor's 500—a market-capitalization weighted index of 500 large U.S. common stocks.

Statistical Array—the large statistical section in the center of each Value Line company report in *Ratings & Reports.* The section contains up to 17 columns of historical information and three columns of estimates on 23 different data items.

Statutory Insurance Accounting (Insurance Industries)—the accounting method required for insurance companies reporting to state insurance regulatory authorities. It is a cash bookkeeping technique, rather than the usual method used in business.

Stock (Common)—units of ownership of a public corporation.

Stock Dividend—the issuance of additional common shares to common stockholders, with no change in total common equity. From an accounting standpoint, retained earnings (i.e., the earned surplus) are reduced and the value of the reported common stock component of common equity (usually called the "par value" account) is increased. (The reduced level of retained earnings is important since bond indentures limit dividend payouts by stipulating minimum levels of retained earnings.) See Stock Split.

Stock (Preferred)—a class of stock that generally has preference over common stock in the payment of dividends and the liquidation of assets and normally pays dividends at a specified rate.

Stock's Price Stability—a relative ranking of the standard deviation of weekly percent changes in the price of a stock over the past five years. The ranks go from 100 for the most stable to 5 for the least stable.

Stock Split—an increase in the number of common shares outstanding by a fixed ratio, say 2-to-1 or 3-to-1, with proportionate allocation of underlying common equity (i.e., the sum of common stock, capital surplus, and retained earnings) and earnings to the increased number of shares outstanding. Total common equity remains the same. From an accounting standpoint, the mix of retained earnings, capital surplus, and common stock remains unchanged. See Stock Dividend. When there is a stock split or dividend, **all historical per-share numbers (including past share prices) are adjusted to reflect the new shares outstanding.** If, for example, a company's stock traded in a range of 40 to 60 last year and it reported earnings of $2.00 per share, after adjustment for a 2-for-1 stock split, the price range for last year would be 20 to 30 and earnings would be $1.00 a share.

Successful Efforts Accounting (Canadian Energy, Natural Gas [Diversified], and Petroleum Industries)—a method of accounting under which exploratory wells found to be dry are expensed as incurred. See Full Cost Accounting.

Supplementary Report—an update of a regular full-page Value Line company report published in the back of the *Ratings & Reports* section when there is a significant development relating to a company. Among the most likely reasons for a Supplementary Report are a major corporate development, such as a merger or acquisition, an unexpectedly good or poor earnings announcement, a change in the sales or earnings outlook, an increase or decrease in the *Timeliness* rank.

Surplus (Insurance Industries)—the amount by which assets exceed liabilities on a legally defined accounting basis.

Target Price Range—the projected average annual price range three to five years hence, based on Value Line earnings and P/E Ratio forecasts. The midpoint of the range is our estimate of the average annual price three to five years from now. The percentage appreciation potential and the estimated annual total return are computed from the projected low and high prices three to five years hence.

Technical Rank—Value Line's proprietary ranking of estimated stock price performance relative to the overall market in the next three to six months, based on a complex analysis of the stock's relative price performance during the previous 52 weeks. Unlike the Timeliness Rank, earnings are not a factor in the Technical Rank. Stocks ranked 1 (Highest) and 2 (Above Average) are likely to outpace the market during the next quarter or two. Those ranked 4 (Below Average) and 5 (Lowest) are expected to underperform most stocks. Stocks ranked 3 (Average) will probably advance or decline with the market. The Technical Rank is purely a function of relative price action and is primarily a predictor of relative short-term price movements. (It may thus be particularly useful in trading short-term instruments such as stock options.) Investors should try to limit purchases to stocks with Technical Ranks of 1 (Highest) and 2 (Average). Under no circumstances, however, should the Technical Rank replace the Timeliness Rank as the primary tool in making an investment decision. Over the years, the Timeliness Rank has had a superior record.

Tender Offer—a way of taking over a company by offering shareholders a fixed (or variable) price for all outstanding stock. If enough shareholders decide to sell, the company can be taken over.

3- to 5-Year Projections—a potential average high and low stock prices Value Line forecasts for a period 3 to 5 years in the future.

Thrift—a financial institution deriving its funds primarily from consumer savings accounts.

Ticker Symbol—the abbreviation of the company's name by which a security is identified for purposes of trading. Also called *Stock Symbol.*

Time Deposits—interest-bearing deposits that a financial institution may require to remain on deposit for a specified period of time. Also called certificates of deposit.

Timeliness Rank—the rank of a stock's probable relative market performance in the year ahead. It is derived via a computer program using as input the long-term price and earnings history, recent price and earnings momentum, and earnings surprise. All data are known and actual. Stocks ranked 1 (Highest) and 2 (Above Average) are likely to outpace the year-ahead market. Those ranked 4 (Below Average) and 5 (Lowest) are expected to underperform most stocks over the next 12 months. Stocks ranked 3 (Average) will probably advance or decline with the market in the year ahead.

Investors should try to limit purchases to stocks ranked 1 (Highest) and 2 (Above Average) for Timeliness.

Timely Industries—see *Industry Timeliness.*

Timely Stocks—those ranked 1 or 2 for *Timeliness.* These are the stocks Value Line thinks will perform better than the Value Line universe as a whole in the coming six to 12 months.

Top Line—a reference to sales, which are usually shown on the top line of an income statement.

Total Capital—the sum of long-term debt, preferred stock at liquidation or redemption value, and common equity including intangibles.

Total Debt—the sum of long-term debt shown in the Capital Structure box and debt due displayed in the Current Position box.

Total Debt Due in 5 Years—the sum of bank notes due in 12 months (or less) and all long-term debt maturing within the next five years (including that portion of long-term debt due in the current operating year). See also Debt Due.

Total Distributions (Investment Companies)—total payments (capital gains plus dividends) made to shareholders of a fund.

Total Interest Coverage—pretax income plus total interest expense (including capitalized interest) divided by total interest expense.

Total Return (%)—the sum of the total appreciation (or depreciation) of a stock over a given period plus any cash dividends received during the same period divided by the price of the stock at the beginning of the period. Each Value Line page shows the total cumulative returns (if available) for the past 1, 3, and 5 years. Each page also denotes the total returns for the Value Line Arithmetic Index for the same periods for comparative purposes. (For more, see Value Line Arithmetic Composite Index)

Total Revenues (Securities Brokerage Industry)—gross revenue from all sources, including commissions, investment banking fees, principal transactions, and interest income (generally without deduction for interest expense) derived from funds loaned to customers' margin accounts plus interest on securities held in the company's account.

Trailing Price Earnings (P/E) Ratio—the recent price of the stock divided by the sum of earnings per share reported during the last 12 months.

Translation Rate (Foreign Stocks)—the exchange rate at which financial data are converted into dollars. Historical data are translated at the exchange rate on the last day of the fiscal year. In the case of quarterly data for the current fiscal year and all estimates, the translation rate is the estimated exchange rate at fiscal year end.

Treasury Stock—common stock issued and then reacquired by the issuing firm. Such reacquisitions result in a reduction of stockholders' equity.

Unconsolidated Income—aftertax earnings of partially or wholly owned subsidiaries whose financial results are not included in the pretax financial results or income taxes reported.

Underwriting Income Per Share (Insurance [Property/Casualty] Industry)—underwriting profit divided by the number of common shares outstanding at year-end.

Underwriting Margin (Insurance Industries)—the difference between 100% and the sum of the loss and expense ratios in property/casualty underwriting. It may be either positive (indicating an underwriting profit) or negative (indicating an underwriting loss).

Unemployment Rate—a Labor Department measure of the ratio of the number of unemployed in the labor force, expressed as a percentage. The Civilian Unemployment Rate is based on a work force that excludes U.S.-stationed members of the armed forces. The National (or Total) Unemployment Rate is based on a work force that includes U.S.-stationed members of the armed forces.

Unit Labor Costs (Nonfarm)—a Labor Department index based on the ratio of the Compensation Per Hour Index (Nonfarm) and the Output Per Hour Index (Nonfarm). Unit labor costs are useful because they illustrate how productivity gains offset rising wages, or how wage increases outstrip productivity gains.

Unrealized Appreciation (or Depreciation)—the dollar amount by which the market value of a holding exceeds (or falls below) its cost.

Untimely Stocks—those ranked 4 or 5 for *Timeliness.* These are stocks Value Line thinks will perform less well than the market in the coming six to 12 months.

Upstream—see Downstream.

Value Line Arithmetic Composite Index—an equally weighted price index of all stocks covered in *The Value Line Investment Survey.* Arithmetic refers to the averaging technique used to compute the average. See Arithmetic Average.

Value Line Geometric Composite Index—an equally weighted price index of all stocks covered in *The Value Line Investment Survey.* Geometric refers to the averaging technique used to compute the average. See Geometric Average.

Value Line Geometric Industrial Index—an equally weighted price index of all stocks in *The Value Line Investment Survey,* except for utilities and rails. Geometric refers to the averaging technique used to compute the average. See Geometric Average.

Value Line Geometric Rails Index—an equally weighted price index of railroad stocks reviewed in *The Value Line Investment Survey.* Geometric refers to the averaging technique used to compute the average. See Geometric Average.

Value Line Geometric Utilities Index—an equally weighted price index of utility stocks reviewed in *The Value Line Investment Survey.* Geometric refers to the averaging technique used to compute the average. See Geometric Average.

Warrant—an option to buy a security, usually a common stock, at a set price (exercise price) over an established number of years. A warrant has no claim on either the equity or the profits of a company.

Working Capital—current assets less current liabilities. See also Current Assets, Current Liabilities, and Net Working Capital.

Writedown—a company's recognition of a reduction in value of an asset. The decline in value is charged against income in the period that the writedown is taken.

Yield (for stocks)—the estimated dividends for the next 12 months divided by the current price, expressed as a percentage.

Yield-Cost Margin (Thrift Industry)—the difference between interest rates earned (on loans and other earning assets) and interest rates paid (on deposits and other sources of funds).

Yield Curve—a measure of the relationship between short-and long-term interest rates. Often the yields on three-month Treasury bills and 30-year Treasury bonds are compared. The yield curve is said to be positive when long-term rates are higher than short-term rates. When short-term and long-term rates are about equal, the yield curve is said to be flat. The yield curve is said to be inverted when short-term rates are higher than long-term rates.

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

EXHIBIT
APS-18
ADMITTED

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01345A-08-0172 **AFFIDAVIT OF DAVID J. RUMOLO IN SUPPORT OF APS'S MOTION FOR APPROVAL OF INTERIM BASE RATE SURCHARGE**

General

1. My name is David J. Rumolo. I am the Manager of Regulation and Pricing of Arizona Public Service Company ("APS" or "Company"). I am responsible for the establishment and administration of APS tariffs and contract provisions that are under the jurisdiction of the Arizona Corporation Commission ("ACC" or "Commission"). I am also responsible for certain aspects of APS tariffs that fall within the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). My business address is 400 North 5th Street, Phoenix, Arizona, 85004.

2. The purpose of this affidavit is to provide testimony on the rate design aspects of the Company's Interim Base Rate Surcharge proposal. I describe alternative rate designs and provide analyses of the bill impacts of the Company's proposal on typical customers.

3. The current \$0.003987/kWh Interim Power Supply Adjustor ("Interim PSA Adjustor") that was authorized in Decision No. 69663 to collect approximately \$46 million will terminate with the last billing cycle of July, 2007. Customers who are billed on that cycle generally will receive their bills during the first week of August.

4. APS has requested that the Commission approve an Interim Base Rate Surcharge equivalent to the \$0.003987/kWh PSA adjustor, and requests that it be effective with the first billing cycle in November 2008 to reduce the continued degradation of the Company's financial position. This aspect of the Company's request is discussed in the affidavit of Mr. Donald Brandt.

5. The Company has analyzed three alternative methods for implementing the Interim Base Rate Surcharge. These are a) assess the surcharge on a per kWh basis similar to the Interim PSA Adjustor; b) assess the surcharge as percentage adder to base bills using an equal percentage increase for all customers; and c) assess the surcharge revenue requirements to customer classes on a per kWh basis but recover the resulting revenue requirements on a demand basis from general service customers whose base rates include demand charges. The last option is the same method that was approved in Decision No. 67744 for the computation of the Demand Side Management Adjustment Charge ("DSMAC"). It would also function similarly to the Transmission Cost Adjustor ("TCA"). Each method will provide the Company with approximately the same revenue but will have differing impacts on customer classes. The Company is proposing that customers who receive service under the low-income and medical equipment rate schedules (Schedules E-3 and E-4) not be charged the Interim Base Rate Surcharge under any of the rate design alternatives since those customers were exempt from the PSA adjustor.

Analysis

6. Based on projected sales in 2008, applying the $0.003987/ kWh charge to forecast sales of 28,862,000 MWh excluding E-3 and E-4 customers, the requested interim relief, were it in effect in 2008 would generate an estimated $115 million as described in the APS request. The proposed interim surcharge would become effective when approved by the Commission and would remain in effect until a final order is issued in the APS rate case Docket No. E-01345A-08-0172.

7. Under the first rate option, the $0.003987/kWh would be applied to all affected customers. For un-metered customers, such as streetlighting sales, the charge would be based on the calculated energy consumption in the same manner as the Interim PSA Adjustor. Therefore, under this option customers would be paying the same as under the PSA and have no bill impact from what they are paying today. However, for high load factor customers served from rates where energy-based charges are a large portion of the bill, an energy-based interim charge results in a greater increase than those customers would experience from a base rate increase that is not based solely on energy.

8. Under the second rate option, the surcharge would be a fixed percentage of base rates applied uniformly across all rate schedules. Based on the assumption that the surcharge is designed to recover $115 million and utilizing adjusted 2007 test year base revenue, the percentage would be approximately 4.4%. The percentage across the board method raises the bills of residential customers and small general service customers slightly more than a "cents per kWh" approach.

9. The third option provides a compromise to the first two options and, as was mentioned earlier is a method similar to the method used for the DSMAC and TCA. The third option is a two-step process. The first step consists of assigning the revenue requirements to customer classes i.e. residential, general service, industrial etc., on an energy basis. Next, for general customers who are billed on rates with explicit demand

charges (e.g. E-32 over 20 kW, E-34, E-35), the revenue requirements are converted to a per kilowatt demand charge. For residential customers, this method results in bill impacts comparable to the first rate option. Attachment DJR-1 presents the details of the calculation of the charges under the three rate options. The table below summarizes the average monthly bill impacts on customers compared to base rate charges for the three options. In both Table 1 and Attachment DJR-1, I have calculated the percentage increase compared to base rate revenues for purposes of consistency. Had I calculated the change as a percentage of the entire customers' bills, including adjusters, the percentages would be slightly lower.

Table 1 – Bill Comparison of Rate Design Options

CUSTOMER CLASS	OPTION 1 (KWH BASIS)	OPTION 2 (% BASIS)	OPTION 3 (KWH OR/KW BASIS)
Residential % increase $ increase	 4.01% $4.66	 4.36% $5.07	 4.01% $4.66
Gen.Serv.-Small % increase $ increase	 4.46% $34.54	 4.36% $33.73	 4.58% $35.40
Lg. Gen. Serv. % increase $ increase	 6.50% $15,980	 4.36% $10,717	 $4.73% $11,624

10. Attachment DJR-2 presents a comparison of bill impacts to customers resulting from the adoption of the requested interim base rate surcharge. The bill impacts are presented based on average annual bills as well as average summer and average winter bills. On an annual basis, a $0.003987/ kWh surcharge results in a $4.66/ month impact for an average residential customer using 1,169 kWh per month. The Company proposed

a procedural schedule on June 30, 2008, that was agreed upon or not opposed by Staff and other parties that would allow the Commission to issue a final resolution of the Company's request by early November. If the proposed Interim Base Rate Surcharge becomes effective with the first billing cycle in November, 2008 that would be coincident with the switch to winter rates. In addition to the benefit of introducing the interim surcharge at a time when billing rates move to lower levels, average consumption is also lower. For the winter season, the average residential customer uses 930 kWh. The $0.003987/kWh interim surcharge would result in a $ 3.71 charge.

Conclusion

11. In summary, each of the three rate options described in my affidavit provide APS with approximately the same level of interim rate relief, and the Company does not have a preference for any one of the options. The choice among the options is largely a matter of customer acceptance of and preference for a particular rate design.

This concludes my affidavit.

State of Arizona)
) ss.
County of Maricopa)

I, David J. Rumolo, having been first duly sworn, state that I have read the foregoing affidavit and that the same is true and correct to the best of my knowledge, information, and belief.

David J. Rumolo

David J. Rumolo

Subscribed and sworn before me this 11 day of July, 2008.

Donna Sue Turner

Notary Public

Notary Public State of Arizona
Maricopa County
Donna Sue Turner
My Commission Expires
04/20/2012

My Commission Expires:

April 20, 2012

ANALYSIS OF INTERIM RATE DESIGN OPTIONS

	2007 Test Year Data				Option 1 Per kWh charge		Option 2 % Increase Charge	Option 3 DSMAC Method	
	Average # of Cust.	Adjusted MWh Sales	Avg annual Use/Cust kWh	Base TY rev present rates ($x1,000)	Revenue $ 0.003987 ($x1000)	% Increase	Revenue @ 4.36%	Revenue $ 0.003987 ($x1000)	% Increase
Residential									
E-10	62,712	526,327	8,393	$ 57,215	$ 2,098	3.67%	$ 2,495	$ 2,098	3.67%
E-12	447,532	4,053,590	9,058	442,588	16,162	3.65%	19,297	16,162	3.65%
EC-1	17,348	343,675	19,811	32,443	1,370	4.22%	1,415	1,370	4.22%
ET-1	353,442	6,181,124	17,488	594,946	24,644	4.14%	25,940	24,644	4.14%
ECT-1R	48,110	1,418,894	29,493	122,822	5,657	4.61%	5,355	5,657	4.61%
ET-2	29,822	724,545	24,296	70,808	2,889	4.08%	3,087	2,889	4.08%
ECT-2	7,048	308,660	43,806	26,213	1,231	4.69%	1,143	1,231	4.69%
Total Residential	966,012	13,556,815	14,034	$ 1,347,035	$ 54,051	4.01%	$ 58,731	$ 54,051	4.01%
General Service									
E-20	329	34,392	104,535	$ 3,267	$ 137	4.20%	$ 142	$ 287	8.77%
E-21	20	1,037	51,850	123	4	3.36%	5	7	5.29%
E-22	13	2,622	201,692	308	10	3.39%	13	29	9.43%
E-23	84	19,246	229,119	1,749	77	4.39%	76	96	5.51%
E-24	38	111,865	2,943,816	7,722	446	5.78%	337	407	5.27%
E-30	4,618	5,648	1,223	1,134	23	1.99%	49	23	1.99%
E-32 (0 to 20 KW)	89,228	1,435,595	16,089	172,703	5,724	3.31%	7,530	5,724	3.31%
E-32 (21 to 100 KW)	18,248	2,727,964	149,495	272,756	10,876	3.99%	11,892	13,759	5.04%
E-32 (101 to 400 KW)	4,058	3,468,621	854,761	292,377	13,829	4.73%	12,748	14,249	4.87%
E-32 (401+ kw)	1,006	4,067,019	4,042,762	306,941	16,215	5.28%	13,383	14,081	4.59%
E-32TOU	64	76,981	1,202,828	5,526	307	5.55%	241	152	2.76%
E-34	39	1,282,858	32,893,795	84,806	5,115	6.03%	3,698	4,064	4.79%
E-35	20	1,554,899	77,744,950	89,217	6,199	6.95%	3,890	4,166	4.67%
E-40	1	1	1,000	1	0	0.40%	0	-	0.00%
E-51	1	8,748	8,748,000	602	35	5.79%	26	27	4.47%
E-55	1	8,170	8,170,000	936	33	3.48%	41	1,308	139.70%
Total General Service	117,768	14,805,686	125,719	$ 1,240,168	$ 59,030	4.76%	$ 54,071	$ 58,378	4.71%
Irrigation and Water Pumping									
E-38, E-38-8T, E-38TOW	71	5,658	79,690	$ 430	$ 23	5.25%	$ 19	$ 39	8.98%
E-221, E-221-8T, E-221TOW	1,397	332,112	237,732	24,946	1,324	5.31%	1,088	1,960	7.86%
Total Irrigation	1,468	337,770	230,089	$ 25,376	$ 1,347	5.31%	$ 1,106	$ 1,999	7.88%
Outdoor Lighting									
E-58	600	31,868	53,113	$ 8,719	$ 127	1.46%	$ 380	$ 127	1.46%
E-59, City Streetlight Contracts	243	82,185	338,210	7,635	328	4.29%	333	328	4.29%
E-67	189	3,944	20,868	176	16	8.83%	8	16	8.83%
Contract	40	10,753	268,825	840	43	5.10%	37	43	5.10%
Total Outdoor Lighting	1,072	128,750	120,103	$ 17,372	$ 513	2.95%	$ 757	$ 513	2.95%
Dusk to Dawn Lighting Service		$ 26,102		$ 7,496	$ 104	1.39%	$ 327	$ 104	1.39%
Total Sales to Ultimate Retail Customers	1,086,320	28,855,123	26,562	$ 2,637,447	$ 115,045	4.36%	$ 114,993	$ 115,045	4.36%
					4.36%				
2007 Sales Subject to E-3/E-4		(485,291)							
2007 E-36 Sales		35,254							
2007 Sales basis for Interim Charge		28,405,086			$ 113,251	4.29%			
2008 Sales (less E-3 and E-4)		28,800,000							
2008 E-36 Sales		62,000							
2008 Sales basis for Interim Charge		28,862,000							

ANALYSIS OF INTERIM RATE DESIGN OPTIONS

Calculation of GS using DSMAC Approach

	Average # of Cust.	Adjusted MWh Sales	Avg annual Use/Cust kWh	Base TY rev present rates ($x1,000)	TY demands	Avg Load Factor	Revenue Based on kW
General Service							
E-20	329	34,392	104,535	$ 3,267	189,966	24.8%	$ 286,546
E-21	20	1,037	51,850	123	4,311	33.0%	6,503
E-22	13	2,622	201,692	308	19,259	18.6%	29,050
E-23	84	19,246	229,119	1,749	63,935	41.2%	96,440
E-24	38	111,865	2,943,816	7,722	269,788	56.8%	406,950
E-30	4,618	5,648	1,223	1,134	-	-	-
E-32 (0 to 20 KW)	89,228	1,435,595	16,089	172,703	-	-	-
E-32 (21 to 100 KW)	18,248	2,727,984	149,495	272,756	9,121,483	41.0%	13,758,893
E-32 (101 to 400 KW)	4,058	3,468,621	854,761	292,377	9,446,689	50.3%	14,249,436
E-32 (401+ kw)	1,006	4,067,019	4,042,762	306,941	9,334,960	59.7%	14,080,903
E-32TOU	64	76,981	1,202,828	5,526	100,979	104.4%	152,317
E-34	39	1,282,858	32,893,795	84,806	2,694,567	65.2%	4,064,499
E-35	20	1,554,899	77,744,950	89,217	2,761,604	77.1%	4,165,618
E-40	1	1	1,000	1	-	-	-
E-51	1	8,748	8,748,000	602	17,850	67.1%	26,925
E-55	1	8,170	8,170,000	936	666,673	1.3%	1,307,596
Total General Service	117,768	14,805,686	125,719	$ 1,240,168	34,892,264	58.1%	$52,631,878
E-38	71	5,658	79,690	$ 430	25,586	30.3%	$ 38,597
E-221	1,397	332,112	237,732	24,946	1,299,684	35.0%	1,960,450
Total Pumping	1,468	337,770	230,089	$ 25,376	1,325,272	34.9%	$ 1,999,047
General Service and Pumping	119,236	15,143,456	355,808	$ 1,265,544	36,217,536	57.3%	$54,630,723

Revenue Requirements @ $0.003987/kWh		54,631
Charge Expressed in $/kW	$	1.508

Computation of Averge Bill Impact	Average Bill (Base Charge)	Option 1		Option 2		Option 3	
Residential	$ 116.20	$ 4.66	4.01%	$ 5.07	4.36%	$ 4.66	4.01%
General Service (E-32)	$ 773.63	$ 34.54	4.46%	$ 33.73	4.36%	$ 35.40	4.58%
Industrial (E34/E35)	$ 245,795	$ 15,980	6.50%	$ 10,717	4.36%	$ 11,624	4.73%

Note: Bill increases due to the proposed Interim Base Rate Surcharge are equivalent to the roll-off of the $0.003987/kWh Interim Power Supply Adjustor for all customers under Option 1 and most customers under Option 3

ARIZONA PUBLIC SERVICE COMPANY
Monthly Bill Impact - Interim Rate

Residential	Annual Monthly Bill	Summer Monthly Bill	Winter Monthly Bill
Average kWh per Month	1,169	1,408	930
Base Rates	$ 116.20	$ 150.41	$ 81.99
PSA - Forward and Historical Components (4.0 mils)	4.68	5.63	3.72
PSA - Interim Adjustor (3.987 mils)	4.66	5.61	3.71
Roll off of PSA - Interim Adjustor (3.987 mils)	(4.66)	(5.61)	(3.71)
All Other Bill Components	3.33	3.73	2.90
Total without Interim Base Rate Adjustor	$ 124.21	$ 159.77	$ 88.61
Bill impact of Interim Base Rate Adjustor (3.987 mils)	**$ 4.66**	**$ 5.61**	**$ 3.71**
Commercial E32			
Average kWh per Month	8,663	9,628	7,698
Base Rates	$ 773.63	$ 912.51	$ 634.75
PSA - Forward and Historical Components (4.0 mils)	34.65	38.51	30.79
PSA - Adjustor (3.987 mils)	34.54	38.39	30.69
Roll off of PSA - Adjustor (3.987 mils)	(34.54)	(38.39)	(30.69)
All Other Bill Components	47.10	52.34	41.84
Total without Interim Base Rate Adjustor	$ 855.38	$ 1,003.36	$ 707.38
Bill impact of Interim Base Rate Adjustor (3.987 mils)	**$ 34.54**	**$ 38.39**	**$ 30.69**
Industrial E34/35			
Average kWh per Month	4,008,132	4,176,596	3,839,667
Base Rates	$ 245,795.07	$ 256,684.48	$ 234,905.67
PSA - Forward and Historical Components (4.0 mils)	16,032.53	16,706.38	15,358.67
PSA - Adjustor (3.987 mils)	15,980.42	16,652.09	15,308.75
Roll off of PSA - Adjustor (3.987 mils)	(15,980.42)	(16,652.09)	(15,308.75)
All Other Bill Components	3,946.24	4,105.94	3,786.54
Total without Interim Base Rate Adjustor	$ 265,773.84	$ 277,496.80	$ 254,050.88
Bill impact of Interim Base Rate Adjustor (3.987 mils)	**$ 15,980.42**	**$ 16,652.09**	**$ 15,308.75**

Notes:
1) Bill excludes regulatory Assessment charge, taxes and fees, but their inclusion would not affect the bill impact due to the Interim Base Rate Surcharge.
2) Bill increases due to the proposed Interim Base Rate Surcharge are equivalent to the roll-off of the $0.003987/kWh Interim Power Supply Adjustor and reflect the Option 1 method for applying the Interim Base Rate Surcharge.

July 11, 2008

EXHIBIT
APS-19
ADMITTED

REBUTTAL TESTIMONY OF DAVID J. RUMOLO

On Behalf of Arizona Public Service Company

Docket No. E-01345A-08-0172

(Interim Rate Request)

September 8, 2008

TABLE OF CONTENTS

REBUTTAL TESTIMONY OF DAVID J. RUMOLO
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-08-0172)
(Interim Rate Request)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David Rumolo. My business address is 400 North Fifth Street, Phoenix, Arizona 85004.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by Arizona Public Service Company ("APS" or "Company") as Manager of Regulation and Pricing. I am responsible for the establishment and administration of APS tariffs and contract provisions that are under the jurisdiction of the Arizona Corporation Commission ("Commission"). I am also responsible for certain aspects of APS tariffs that fall within the jurisdiction of the Federal Energy Regulatory Commission ("FERC").

Q. WOULD YOU DISCUSS YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE?

A. My background and experience are set forth in Appendix A to this testimony.

Q. HAVE YOU FILED ANY PREVIOUS TESTIMONY REGARDING THE PROPOSED INTERIM RATE INCREASE?

A. Yes, on July 11, 2008, I filed an affidavit that addressed alternative rate designs for the interim rate increase. That affidavit described three alternatives; a kilowatthour charge that would be applicable to all affected customers, a percentage method that would apply the same percentage to all affected customers, and a hybrid in which the revenue responsibility is assigned to customer classes on a per kWh charge but is collected from commercial and industrial customers on the basis of demand. In each case, customers who are eligible to receive low-income discounts under the provisions of Rate Schedules E-3 and E-4 would be exempt from the interim increase. As described in my affidavit, APS has no preference regarding the three options.

II. SUMMARY

Q. WOULD YOU SUMMARIZE YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony focuses on two areas. First, I provide a discussion on the interim revenue requirement that was computed by Staff Consultant Ralph Smith. Mr. Smith provided his revenue requirements computation as an alternative should the Commission determine that APS should be allowed an interim increase. Mr. Smith's calculations are based on the plant additions made by APS between the test year rate base in APS's last rate case (TYE 9/30/2005) to the unadjusted test year rate base found in the current rate case filing (TYE 12/31/2007). He computed the increased revenue requirements of approximately $65 million associated with the return on investment for the increased plant investment. In my rebuttal testimony, I note that Mr. Smith failed to include other fixed costs associated with plant investment, most notably depreciation and property taxes.

My testimony provides analyses of several additional alternatives that build on the concept developed by Staff Consultant Smith. The alternatives include developing the revenue requirements for plant additions that are in service and serving customers today but are not included in current rates. For example, utilizing data found in the direct testimony of APS Witness Daniel Kearns in the APS permanent rate case, I added the revenue requirements associated with known and measurable generation plant additions as of June 30, 2008. The addition of the generation plant alone increases the interim rate increase revenue requirements to $118 million which exceeds the interim increase requested by the Company.

Second, my rebuttal testimony addresses the rate design testimony submitted by Mr. Smith and by Arizonans for Electric Choice and Competition ("AECC") Witness Kevin Higgins. In his testimony, Mr. Smith suggests that should the Commission authorize interim rate relief, the per kilowatthour rate design is the preferred approach. Mr. Higgins testimony indicates that the percentage approach is more appropriate. My testimony comments on the testimony of Mr. Smith and Mr. Higgins.

III. REVENUE REQUIREMENTS ANALYSES

Q. HAVE YOU REVIEWED THE REVENUE REQUIREMENTS ANALYSIS PREPARED BY STAFF WITNESS RALPH SMITH?

A. Yes, I have. Mr. Smith's testimony states that if the Commission desired to provide some level of interim rate relief, the appropriate level of the relief would be approximately $65 million. His testimony notes that this level was developed by comparing the rate base level authorized by the Commission in APS's last rate case in Decision No. 69663 and the unadjusted rate base for the test year ending December 31, 2007. Mr. Smith then applies the rate of return authorized in Decision No. 69663 to the change in rate base to develop the revenue requirement with the appropriate change in interest synchronization.

Q. DO YOU AGREE WITH THE APPROACH UTILIZED BY MR. SMITH?

A. The steps undertaken by Mr. Smith are mathematically correct, but I do not believe that he has fully applied his methodology.

Q. PLEASE ELABORATE ON YOUR LAST COMMENT.

A. Mr. Smith calculates the return on some but not all of the increased capital investment since the last rate case test year. However, he does not include the other fixed costs of that capital investment, the largest of which are return of capital through depreciation expense and property taxes.

Q. ARE THERE OTHER COSTS THAT HAVE NOT BEEN INCLUDED IN MR. SMITH'S CALCULATIONS?

A. Yes, plant-related fixed operations and maintenance expenses associated with the new facilities have not been included. As APS installs more equipment, fixed operations and maintenance expenses related to that equipment also increase. However, these costs are relatively small compared to those I have already identified, namely return, depreciation, and property taxes.

Q. HAVE YOU ADJUSTED MR. SMITH'S CALCULATIONS FOR THE ADDITIONAL REVENUE REQUIREMENTS DUE TO DEPRECIATION EXPENSE AND PROPERTY TAXES?

A. Yes, I did. Attachment DJR_RB-1 demonstrates the calculations. I began with Mr. Smith's calculations, added depreciation expense and property tax expense for the increased plant in service as of December 31, 2007. These two cost factors increased the interim revenue requirements to approximately $107.7 million. I also have not included the increased revenue requirements that result from operations and maintenance expenses for the reasons discussed above.

Q. HAVE YOU COMPUTED THE RATE IMPACTS OF MR. SMITH'S ALTERNATIVE AND YOUR MODIFICATION TO THAT ALTERNATIVE?

A. Yes. Adjusted 2007 test year billing determinants, excluding the energy associated with customers receiving low-income discounts, amount to 28,405,086 MWh. Mr. Smith's alternative would yield a rate of $0.0023 per kWh. With APS's modifications to Mr. Smith's alternative, a rate of $0.0038 per kWh would yield the revenue requirements of approximately $107.7 million.

Q. HAVE YOU EXAMINED OTHER MODIFICATIONS TO MR. SMITH'S REVENUE REQUIREMENTS COMPUTATIONS?

A. Yes. Since the end of the 2007 test year, APS has completed construction of several significant additions to our generation investment that have been placed in service. We have added the steam generator upgrades for Palo Verde Unit #3, the Yucca combustion generator units in Yuma and APS's share of the environmental construction upgrades at the Cholla Plant. These projects have added approximately $184 million to jurisdictional rate base since the close of the 2007 books. The revenue requirement increase resulting from these generation additions is approximately $10.6 million using the rate of return authorized in Decision No 69663. When added to the $107.7 million computed previously, the interim revenue requirement (again excluding increased operations and maintenance expenses) is approximately $118.4 million or $0.0042 per kWh.

Q. DID YOU EXAMINE ANY OTHER ALTERNATIVES?

A. Yes. We examined all the jurisdictional plant balances closed to utility plant as of 6/30/2008 net of accumulated depreciation, deferred taxes and retirements. As of that date, APS had added over $350 million in utility plant, including the generation additions described in my previous answer, and distribution plant compared to the 12/31/2007 test year rate base. Using Mr. Smith's same calculation method (including the plant additions from the end of the last rate case test year thru 12/31/2007), plus the addition of depreciation expense and property taxes, an interim rate increase of $137.9 million could be supported. This amount recognizes the fixed costs of the net rate base invested by APS since the end of the last rate case test year. Again, I have not included any expense adjustments to reflect increased operations and maintenance expenses.

Q. **DO YOU BELIEVE THAT THE CALCULATIONS YOU HAVE DESCRIBED ARE CONSERVATIVE?**

A. Yes, I do. The generation plant additions that I described are based on the rate base value of the plant as of October 2009 per the pro forma calculations found in the rate case testimony of APS Witness Daniel Kearns. Today's rate base value would be slightly higher due to lower accumulated depreciation, i.e. partial year depreciation compared to full year. Also, we have used the rate of return authorized in Decision No. 69663, not the rate of return requested in our current rate case. Finally, as I noted in the previous question, we have not attempted to adjust any operations and maintenance expenses for the increased plant investment.

Q. **DOES ATTACHMENT DJR_RB-1 PROVIDE THE CALCULATIONS FOR EACH OF THE ALTERNATIVES THAT YOU HAVE DESCRIBED?**

A. Yes it does. The attachment replicates the calculations of Mr. Smith (Scenario 1), then adds depreciation and property tax expense (Scenario 2). Scenario 3 adds the impact of the generation plant investment additions to Scenario 2. Scenario 4 demonstrates the calculations incorporating the changes between

12/31/2007 and 6/30/2008 in non-transmission plant additions (including generation additions), increased accumulated depreciation and deferred taxes.

IV. RATE DESIGN

Q. HAVE YOU REVIEWED THE TESTIMONY OF STAFF AND AECC REGARDING RATE DESIGNS FOR IMPLEMENTING THE INTERIM REQUEST?

A. Yes, I have. Staff Consultant Ralph Smith proposes that should the Commission approve an interim rate change, it should be applied to customer bills on the basis of a per kilowatthour charge. AECC Witness Kevin Higgins proposes that the interim increase be assessed on a percentage basis, with the same percentage applied to all customer classes. Although neither Mr. Smith nor Mr. Higgins specifically address the APS suggested exemption for customers who receive low income discounts under Rate Schedules E-3 and E-4, I have assumed that Staff and AECC are supportive of that exemption.

Q. IN YOUR AFFIDAVIT, YOU INDICATED THAT APS IS WILLING TO UTILIZE ANY OF THE THREE METHODS THAT YOU DESCRIBE. IS THAT STILL THE COMPANY'S POSITION?

A. Yes it is. As noted in my affidavit, the per kWh approach tends to benefit small energy users such as residential customers but is a disadvantage for large consumers of energy. The percentage method tends to favor large users. For small users, the per kWh method is beneficial since the basic service charge fixed fee is a larger percentage of the total bill than for large users. A percentage would be applied to the total base bill, including the basic service charge. Other adjusters, taxes, etc. would be excluded from the percentage adder. The opposite is true for large users. The energy component of the customer's bill is a significant portion of the total bill, therefore, a percentage method would yield a smaller increase than a per kWh charge.

The third method as described in my affidavit allocates the revenue responsibility on a per kWh basis but collects on a capacity basis from general service customers who are billed with a rate demand component. The effect of that method is to re-allocate the revenue responsibility within the general service customer class. AECC is correct in noting that this is a hybrid approach, but it is the hybrid approach that has been used by the Commission with regard to other costs such as recovery of demand side management program costs.

APS believes that each of the approaches are equally simple to implement, administer and track should there be a need to make refunds in the future.

V. CONCLUSION

Q. WOULD YOU PLEASE SUMMARIZE CONCLUSIONS REACHED IN YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony addresses the following key issues: 1) Staff Consultant Ralph Smith provides a reasonable approach to computing the revenue requirements that could be used to compute interim rate relief if done properly. 2) The Staff method omits two plant investment expenses, depreciation and property taxes. These are fixed investment carrying costs that the company bears when plant is placed in service. Adding these cost elements to Mr. Smith's approach increases the interim relief from approximately $65.2 million to $107.7 million. 3) The Staff approach should be further expanded to recognize, at a minimum, the additional generation plant investments that have been completed in 2008. The interim rate relief with that addition would be approximately $118.4 million. If the interim relief was based on all non-transmission plant added through 6/30/2008, the interim revenue requirements would be approximately $137.9 million. 4) APS expresses no preference regarding the rate design that will be applied to customer bills should the commission grant interim relief.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Appendix A
Statement of Qualifications
David J. Rumolo

David J. Rumolo is Arizona Public Service Company's Manager of State Pricing. He has over 32 years experience in the electric utility business as a consultant and utility professional. Mr. Rumolo holds Bachelor of Science Degrees in Electrical Engineering and Business (Finance as an area of emphasis) from the University of Colorado. He is a registered professional engineer in the states of Arizona, California, and New Mexico.

Mr. Rumolo's areas of expertise include utility Rate Schedule design; embedded and marginal cost analysis; formulation of utility service policies; contract development and negotiation; utility valuation analyses; and evaluation of utility revenue requirements. Mr. Rumolo has testified on utility matters before state regulatory bodies in the states of Arizona, Colorado, Florida, and Wyoming and before judicial bodies in the states of Arizona and California. Mr. Rumolo is also experienced in the many aspects of electric utility planning and design including preparation of long-range resource plans; transmission and distribution system long range planning; system protection analyses; and reliability assessments.

Mr. Rumolo has held his current position at Arizona Public Service Company for approximately seven years. Prior to assuming that position, he served as the Manager of Transmission and Market Structure Assessment for Pinnacle West Energy Corporation ("PWEC"). Before joining PWEC, Mr. Rumolo had a 15-year career as a consultant with Resource Management International, Inc., where he provided utility Rate Schedule and engineering consulting services to utility clients across the United States and overseas. He began his career providing consulting services to utility clients when he joined the firm of Miner and Miner Consulting Engineers in Greeley, Colorado where he became the Manager of Planning and Rate Schedules. He later became a partner in Electrical Systems Consultants where he focused on cost of service and Rate Schedule analyses, as well as transmission and distribution planning.

Arizona Public Service Company
Computation of Increase in Gross Revenue Requirement
On Change in Rate Base Since Decision No. 69663
ACC Jurisdictional

Test Year Ended December 31, 2007
(Thousands of Dollars)

Line No.	Description	Scenario 1 Staff Direct Testimony	Scenario 2 Staff Direct Testimony With Increased Depreciation & Property Tax Expense	Scenario 3 Staff Direct Testimony With Proformas - PV Unit 3 SG, Cholla, & Yucca Units 5&6	Scenario 4 6/30/2008 (g) Plant Additions
1	Adjusted Rate Base Additions	$ 537,987	$ 537,987	$ 585,653	$ 696,424
2	Rate of Return	8.32%	8.32%	8.32%	8.32%
3	Operating Income Required	$ 44,761	$ 44,761	$ 48,726	$ 57,942
4	Net Operating Income Available	$ 5,209	$ 5,209	$ 5,671	$ 6,743
5	Operating Income Excess/Deficiency	$ 39,552	$ 39,552	$ 43,055	$ 51,199
6	Gross Revenue Conversion Factor	1.6491	1.6491	1.6491	1.6491
7	Base Rate Revenue Increase for Interim Rates Due To Change in Rate Base	$ 65,225	$ 65,225	$ 71,002	$ 84,432
8	Depreciation Expense Adjustment	$ -	$ 30,588 (a)	$ 34,464 (b)	$ 38,848 (c)
9	Total Revenue Requirement Increase with Deprec. Expense	$ 65,225	$ 95,813	$ 105,466	$ 123,280
10	Property Tax Adjustment	$ -	$ 11,919 (d)	$ 12,907 (e)	$ 14,615 (f)
11	Total Revenue Requirement Increase	$ 65,225	$ 107,732	$ 118,373	$ 137,895
12	Retail Revenue Requirement Increase per $/kWh	$ 0.0023	$ 0.0038	$ 0.0042	$ 0.0049

(a) Depreciation Expense Adjustment factor of 2.746% based on 2007 Depreciation Expense (FERC Form 1, Page 219, Line 10) divided by 2007 Total Electric Plant In Service (FERC Form 1, Page 207, Line 104) applied to change in Gross Utility Plant in Service from Schedule B-1 (ACC - Column (D), Line 1) for TYE 9/30/2005 and TYE 12/31/2007.

(b) Proforma Depreciation Expense from Schedule C-2 (ACC - Column B, D & F - Line 10) added to Depreciation Expense in Scenario 2.

(c) Depreciation Expense Adjustment factor of 2.746% based on 2007 Depreciation Expense (FERC Form 1, Page 219, Line 10) divided by 2007 Total Electric Plant In Service (FERC Form 1, Page 207, Line 104) applied to change in Gross Utility Plant in Service from Schedule B-1 (ACC - Column (D), Line 1) for TYE 9/30/2005 and TYE 12/31/2007 and 6/30/2008 plant additions.

(d) Property Tax Expense Adjustment factor of 1.07% based on 2007 Real & Personal Property Charged Taxes (FERC Form 1, Page 263, Line 9, 17, 26 & 31) divided by 2007 Total Electric Plant In Service (FERC Form 1, Page 207, Line 104) applied to change in Gross Utility Plant in Service from Schedule B-1 (ACC - Column (D), Line 1) for TYE 9/30/2005 and TYE 12/31/2007.

(e) Proforma Property Tax Expense from Schedule C-2 (ACC - Column B, D & F - Line 13) added to Property Tax Expense in Scenario 2.

(f) Property Tax Expense Adjustment factor of 1.07% based on 2007 Real & Personal Property Charged Taxes (FERC Form 1, Page 263, Line 9, 17, 26 & 31) divided by 2007 Total Electric Plant In Service (FERC Form 1, Page 207, Line 104) applied to change in Gross Utility Plant in Service from Schedule B-1 (ACC - Column (D), Line 1) for TYE 9/30/2005 and TYE 12/31/2007 and 6/30/2008 plant additions.

(g) Includes generation plant shown in Scenario 3.

Arizona Public Service Company
Interest Synchronization

Test Year Ended December 31, 2007
(Thousands of Dollars)

Line No.	Description	Scenario 1 Staff Direct Testimony	Scenario 2 Staff Direct Testimony With Increased Depreciation & Property Tax Expense	Scenario 3 Staff Direct Testimony With Proformas - PV Unit 3 SG, Cholla, & Yucca Units 5&6	Scenario 4 6/30/2008 Plant Additions
1	Change in Jurisdictional Rate Base	$ 537,987	$ 537,987	$ 585,653	$ 696,424
2	Weighted Cost of Debt	2.46%	2.46%	2.46%	2.46%
3	Synchronized Interest Deduction	$ 13,234	$ 13,234	$ 14,407	$ 17,132
4	Difference (decreased) increased interest deduction	$ 13,234	$ 13,234	$ 14,407	$ 17,132
5	Combined Federal and State Income Tax Rates	39.360%	39.360%	39.360%	39.360%
6	Increase (decrease) to Income Tax Expense	$ (5,209)	$ (5,209)	$ (5,671)	$ (6,743)
7	Increase (decrease) to Net Operating Income	$ 5,209	$ 5,209	$ 5,671	$ 6,743

Arizona Public Service Company
Summary of Rate Base Change
From Decision No. 69663
ACC Jurisdictional

Test Year Ended December 31, 2007
(Thousands of Dollars)

Line No.	Description	Scenario 1 Staff Direct Testimony	Scenario 2 Staff Direct Testimony With Increased Depreciation & Property Tax Expense	Scenario 3 Staff Direct Testimony With Proformas - PV Unit 3 SG, Cholla, & Yucca Units 5&6	Scenario 4 6/30/2008 Plant Additions
1	Decision No. 69663	$ 4,403,496	$ 4,403,496	$ 4,403,496	$ 4,403,496
2	Current Case - Unadjusted (12/31/2007)	$ 4,941,483	$ 4,941,483	$ 4,941,483	$ 4,941,483
3	Adjusted Rate Base	$537,987	$537,987	$537,987	$537,987
4	Palo Verde Unit 3 Steam Generator (a)			$ 92,199	
5	Cholla Generating Station Env. Projects (b)			$ 15,608	
6	Yucca Units 5 & 6 (c)			$ 75,758	
7	Increase in ACC Accumulated Deferred Income Taxes			$ (135,899)	
8	Revised Adjusted Rate Base			$585,653	
9	6/30/2008 ACC Post Test Year Plant Additions (d)				$ 343,220
10	Increase in ACC Accumulated Depreciation Reserve (e)				$ (48,884)
11	Increase in ACC Accumulated Deferred Income Taxes				$ (135,899)
12	Revised Adjusted Rate Base				$696,424

(a) Filed Schedule B-2 (Column D)

(b) Filed Schedule B-2 (Column F)

(c) Filed Schedule B-2 (Column H)

(d) Increase calculated by subtracting FERC Form 1 Functional Plant In Service numbers (Pages 204-207, Column (g)) from Form 3-Q: Quarterly Financial Report for 2008/Q2 (Page 208, Column (b)) exclusive of transmission plant. This number includes production proformas from Scenario 3 and is net of retirements.

(e) Increase calculated by subtracting 12/31/2007 Year End Balance from Current End of Quarter Balance [Form 3-Q: Quarterly Financial Report for 2008/Q2 (Page 110, Column (d-c))] exclusive of transmission.

EXHIBIT

APS-20

ARIZONA PUBLIC SERVICE COMPANY

Monthly Bill Impact - Interim Rate

APS Requested $115 million Revenue, Option 1 Interim Rate as Equal kWh Charge

Residential	Annual Monthly Bill	Summer Monthly Bill	Winter Monthly Bill
Average kWh per Month	1,169	1,408	930
Base Rates	$ 116.20	$ 150.41	$ 81.99
PSA - Forward and Historical Components (4.0 mils)	4.68	5.63	3.72
PSA - Interim Adjustor (3.987 mils)	4.66	5.61	3.71
Roll off of PSA - Interim Adjustor (3.987 mils)	(4.66)	(5.61)	(3.71)
All Other Bill Components	3.33	3.73	2.90
Total without Interim Base Rate Surcharge	$ 124.21	$ 159.77	$ 88.61
Bill impact of Interim Base Rate Surcharge (3.987 mils)	**$ 4.66**	**$ 5.61**	**$ 3.71**
Commercial E32			
Average kWh per Month	8,663	9,628	7,698
Base Rates	$ 773.63	$ 912.51	$ 634.75
PSA - Forward and Historical Components (4.0 mils)	34.65	38.51	30.79
PSA - Adjustor (3.987 mils)	34.54	38.39	30.69
Roll off of PSA - Adjustor (3.987 mils)	(34.54)	(38.39)	(30.69)
All Other Bill Components	47.10	52.34	41.84
Total without Interim Base Rate Surcharge	$ 855.38	$ 1,003.36	$ 707.38
Bill impact of Interim Base Rate Surcharge (3.987 mils)	**$ 34.54**	**$ 38.39**	**$ 30.69**
Industrial E34/35			
Average kWh per Month	4,008,132	4,176,596	3,839,667
Base Rates	$ 245,795.07	$ 256,684.48	$ 234,905.67
PSA - Forward and Historical Components (4.0 mils)	16,032.53	16,706.38	15,358.67
PSA - Adjustor (3.987 mils)	15,980.42	16,652.09	15,308.75
Roll off of PSA - Adjustor (3.987 mils)	(15,980.42)	(16,652.09)	(15,308.75)
All Other Bill Components	3,946.24	4,105.94	3,786.54
Total without Interim Base Rate Surcharge	$ 265,773.84	$ 277,496.80	$ 254,050.88
Bill impact of Interim Base Rate Surcharge (3.987 mils)	**$ 15,980.42**	**$ 16,652.09**	**$ 15,308.75**

Notes:

1) Bill excludes regulatory Assessment charge, taxes and fees, but their inclusion would not affect the bill impact due to the Interim Base Rate Surcharge.
2) Bill increases due to the proposed Interim Base Rate Surcharge are equivalent to the roll-off of the $0.003987/kWh Interim Power Supply Adjustor and reflect the Option 1 method for applying the Interim Base Rate Surcharge.
3) Interim Base Rate Surcharge would not be applied to E-3 and E-4 customers and would apply to E-36 customers

September 12, 2008

ARIZONA PUBLIC SERVICE COMPANY

Monthly Bill Impact - Interim Rate

APS Requested $115 million Revenue, Option 2 Interim Rate as Equal % Adder Charge

Residential	Annual Monthly Bill	Summer Monthly Bill	Winter Monthly Bill
Average kWh per Month	1,169	1,408	930
Base Rates	$ 116.20	$ 150.41	$ 81.99
PSA - Forward and Historical Components (4.0 mils)	4.68	5.63	3.72
PSA - Interim Adjustor (3.987 mils)	4.66	5.61	3.71
Roll off of PSA - Interim Adjustor (3.987 mils)	(4.66)	(5.61)	(3.71)
All Other Bill Components	3.33	3.73	2.90
Total without Interim Base Rate Surcharge	$ 124.21	$ 159.77	$ 88.61
Bill impact of Interim Base Rate Surcharge (4.36%)	**$ 5.07**	**$ 6.56**	**$ 3.57**
Commercial E32			
Average kWh per Month	8,663	9,628	7,698
Base Rates	$ 773.63	$ 912.51	$ 634.75
PSA - Forward and Historical Components (4.0 mils)	34.65	38.51	30.79
PSA - Adjustor (3.987 mils)	34.54	38.39	30.69
Roll off of PSA - Adjustor (3.987 mils)	(34.54)	(38.39)	(30.69)
All Other Bill Components	47.10	52.34	41.84
Total without Interim Base Rate Surcharge	$ 855.38	$ 1,003.36	$ 707.38
Bill impact of Interim Base Rate Surcharge (4.36%)	**$ 33.73**	**$ 39.79**	**$ 27.68**
Industrial E34/35			
Average kWh per Month	4,008,132	4,176,596	3,839,667
Base Rates	$ 245,795.07	$ 256,684.48	$ 234,905.67
PSA - Forward and Historical Components (4.0 mils)	16,032.53	16,706.38	15,358.67
PSA - Adjustor (3.987 mils)	15,980.42	16,652.09	15,308.75
Roll off of PSA - Adjustor (3.987 mils)	(15,980.42)	(16,652.09)	(15,308.75)
All Other Bill Components	3,946.24	4,105.94	3,786.54
Total without Interim Base Rate Surcharge	$ 265,773.84	$ 277,496.80	$ 254,050.88
Bill impact of Interim Base Rate Surcharge (4.36%)	**$ 10,716.67**	**$ 11,191.44**	**$ 10,241.89**

Notes:

1) Bill excludes regulatory Assessment charge, taxes and fees, but their inclusion would not affect the bill impact due to the Interim Base Rate Surcharge.
2) Bill increases due to the proposed Interim Base Rate Surcharge are equivalent to the roll-off of the $0.003987/kWh Interim Power Supply Adjustor and reflect the Option 2 method for applying the Interim Base Rate Surcharge.
3) Interim Base Rate Surcharge would not be applied to E-3 and E-4 customers and would apply to E-36 customers

ARIZONA PUBLIC SERVICE COMPANY
Monthly Bill Impact - Interim Rate
APS Requested $115 million Revenue, Option 3 Interim Rate as kW Charge for C&I Customers
Interim Rate Surcharge would not be applied to E-3 and E-4 customers and would apply to E-36 customers

Residential	Annual Monthly Bill	Summer Monthly Bill	Winter Monthly Bill
Average kWh per Month	1,169	1,408	930
Base Rates	$ 116.20	$ 150.41	$ 81.99
PSA - Forward and Historical Components (4.0 mils)	4.68	5.63	3.72
PSA - Interim Adjustor (3.987 mils)	4.66	5.61	3.71
Roll off of PSA - Interim Adjustor (3.987 mils)	(4.66)	(5.61)	(3.71)
All Other Bill Components	3.33	3.73	2.90
Total without Interim Base Rate Surcharge	$ 124.21	$ 159.77	$ 88.61
Bill impact of Interim Base Rate Surcharge (3.987 mils per kWh)	**$ 4.66**	**$ 5.61**	**$ 3.71**
Commercial E32			
Average kWh per Month	8,663	9,628	7,698
Base Rates	$ 773.63	$ 912.51	$ 634.75
PSA - Forward and Historical Components (4.0 mils)	34.65	38.51	30.79
PSA - Adjustor (3.987 mils)	34.54	38.39	30.69
Roll off of PSA - Adjustor (3.987 mils)	(34.54)	(38.39)	(30.69)
All Other Bill Components	47.10	52.34	41.84
Total without Interim Base Rate Surcharge	$ 855.38	$ 1,003.36	$ 707.38
Bill impact of Interim Base Rate Surcharge ($1.508 per kW) (3)	**$ 43.58**	**$ 46.90**	**$ 40.41**
Industrial E34/35			
Average kWh per Month	4,008,132	4,176,596	3,839,667
Base Rates	$ 245,795.07	$ 256,684.48	$ 234,905.67
PSA - Forward and Historical Components (4.0 mils)	16,032.53	16,706.38	15,358.67
PSA - Adjustor (3.987 mils)	15,980.42	16,652.09	15,308.75
Roll off of PSA - Adjustor (3.987 mils)	(15,980.42)	(16,652.09)	(15,308.75)
All Other Bill Components	3,946.24	4,105.94	3,786.54
Total without Interim Base Rate Surcharge	$ 265,773.84	$ 277,496.80	$ 254,050.88
Bill impact of Interim Base Rate Surcharge ($1.508 per kW) (4)	**$ 11,620.80**	**$ 12,109.24**	**$ 11,132.36**

Notes:
1) Bill excludes regulatory Assessment charge, taxes and fees, but their inclusion would not affect the bill impact due to the Interim Base Rate Surcharge.
2) Bill increases due to the proposed Interim Base Rate Surcharge are equivalent to the roll-off of the $0.003987/kWh Interim Power Supply Adjustor and reflect the Option 3 method for applying the Interim Base Rate Surcharge.
3) Based on a medium E32 customer using 8,663 kWh per month - annual average
4) Impacts assume equal load factor across seasons for E34 and E35
3) Interim Base Rate Surcharge would not be applied to E-3 and E-4 customers and would apply to E-36 customers

September 12, 2008

ARIZONA PUBLIC SERVICE COMPANY
Monthly Bill Impact - Interim Rate
Staff Alternative of $65,225,000 Interim Revenue Recovered thru kWh charge

Residential		Annual Monthly Bill		Summer Monthly Bill		Winter Monthly Bill
Average kWh per Month		1,169		1,408		930
Base Rates	$	116.20	$	150.41	$	81.99
PSA - Forward and Historical Components (4.0 mils)		4.68		5.63		3.72
PSA - Interim Adjustor (3.987 mils)		4.66		5.61		3.71
Roll off of PSA - Interim Adjustor (3.987 mils)		(4.66)		(5.61)		(3.71)
All Other Bill Components		3.33		3.73		2.90
Total without Interim Base Rate Surcharge	$	124.21	$	159.77	$	88.61
Bill impact of Interim Base Rate Surcharge (2.3 mils)	**$**	**2.69**	**$**	**3.24**	**$**	**2.14**
Commercial E32						
Average kWh per Month		8,663		9,628		7,698
Base Rates	$	773.63	$	912.51	$	634.75
PSA - Forward and Historical Components (4.0 mils)		34.65		38.51		30.79
PSA - Adjustor (3.987 mils)		34.54		38.39		30.69
Roll off of PSA - Adjustor (3.987 mils)		(34.54)		(38.39)		(30.69)
All Other Bill Components		47.10		52.34		41.84
Total without Interim Base Rate Surcharge	$	855.38	$	1,003.36	$	707.38
Bill impact of Interim Base Rate Surcharge (2.3 mils)	**$**	**19.92**	**$**	**22.14**	**$**	**17.71**
Industrial E34/35						
Average kWh per Month		4,008,132		4,176,596		3,839,667
Base Rates	$	245,795.07	$	256,684.48	$	234,905.67
PSA - Forward and Historical Components (4.0 mils)		16,032.53		16,706.38		15,358.67
PSA - Adjustor (3.987 mils)		15,980.42		16,652.09		15,308.75
Roll off of PSA - Adjustor (3.987 mils)		(15,980.42)		(16,652.09)		(15,308.75)
All Other Bill Components		3,946.24		4,105.94		3,786.54
Total without Interim Base Rate Surcharge	$	265,773.84	$	277,496.80	$	254,050.88
Bill impact of Interim Base Rate Surcharge (2.3 mils)	**$**	**9,218.70**	**$**	**9,606.17**	**$**	**8,831.23**

Notes:

1) Bill excludes regulatory Assessment charge, taxes and fees, but their inclusion would not affect the bill impact due to the Interim Base Rate Surcharge.
2) Bill impact computed based on $65,225,000 revenue requirement and adjusted test year MWh, excluding E-3 and E-4 and including E-36
3) Interim Base Rate Surcharge would not be applied to E-3 and E-4 customers and would apply to E-36 customers

September 12, 2008

ARIZONA PUBLIC SERVICE COMPANY
Monthly Bill Impact - Interim Rate
AECC Proposal: $42.4 million recovered thru a 1.61 % adjuster

Residential	Annual Monthly Bill	Summer Monthly Bill	Winter Monthly Bill
Average kWh per Month	1,169	1,408	930
Base Rates	$ 116.20	$ 150.41	$ 81.99
PSA - Forward and Historical Components (4.0 mils)	4.68	5.63	3.72
PSA - Interim Adjustor (3.987 mils)	4.66	5.61	3.71
Roll off of PSA - Interim Adjustor (3.987 mils)	(4.66)	(5.61)	(3.71)
All Other Bill Components	3.33	3.73	2.90
Total without Interim Base Rate Surcharge	$ 124.21	$ 159.77	$ 88.61
Bill impact of Interim Base Rate Surcharge (1.61% on base)	**$ 1.87**	**$ 2.42**	**$ 1.32**

Commercial E32			
Average kWh per Month	8,663	9,628	7,698
Base Rates	$ 773.63	$ 912.51	$ 634.75
PSA - Forward and Historical Components (4.0 mils)	34.65	38.51	30.79
PSA - Adjustor (3.987 mils)	34.54	38.39	30.69
Roll off of PSA - Adjustor (3.987 mils)	(34.54)	(38.39)	(30.69)
All Other Bill Components	47.10	52.34	41.84
Total without Interim Base Rate Surcharge	$ 855.38	$ 1,003.36	$ 707.38
Bill impact of Interim Base Rate Surcharge (1.61% on base)	**$ 12.46**	**$ 14.69**	**$ 10.22**

Industrial E34/35			
Average kWh per Month	4,008,132	4,176,596	3,839,667
Base Rates	$ 245,795.07	$ 256,684.48	$ 234,905.67
PSA - Forward and Historical Components (4.0 mils)	16,032.53	16,706.38	15,358.67
PSA - Adjustor (3.987 mils)	15,980.42	16,652.09	15,308.75
Roll off of PSA - Adjustor (3.987 mils)	(15,980.42)	(16,652.09)	(15,308.75)
All Other Bill Components	3,946.24	4,105.94	3,786.54
Total without Interim Base Rate Surcharge	$ 265,773.84	$ 277,496.80	$ 254,050.88
Bill impact of Interim Base Rate Surcharge (1.61% on base)	**$ 3,957.30**	**$ 4,132.62**	**$ 3,781.98**

Notes:
1) Bill excludes regulatory Assessment charge, taxes and fees, but their inclusion would not affect the bill impact due to the Interim Base Rate Surcharge.
2) Bill impact based on $42.4 million revenue requirements and adjusted test year base revenue of $2,637,447,000

September 12, 2008

ARIZONA PUBLIC SERVICE COMPANY
Monthly Bill Impact - Interim Rate
Modified AECC Proposal: $42.4 million recovered thru a 1.63 % adjuster
Excluding E-3 and E-4 Customers, Including E-36

Residential	Annual Monthly Bill	Summer Monthly Bill	Winter Monthly Bill
Average kWh per Month	1,169	1,408	930
Base Rates	$ 116.20	$ 150.41	$ 81.99
PSA - Forward and Historical Components (4.0 mils)	4.68	5.63	3.72
PSA - Interim Adjustor (3.987 mils)	4.66	5.61	3.71
Roll off of PSA - Interim Adjustor (3.987 mils)	(4.66)	(5.61)	(3.71)
All Other Bill Components	3.33	3.73	2.90
Total without Interim Base Rate Surcharge	$ 124.21	$ 159.77	$ 88.61
Bill impact of Interim Base Rate Surcharge (1.63% on base)	**$ 1.89**	**$ 2.45**	**$ 1.34**

Commercial E32			
Average kWh per Month	8,663	9,628	7,698
Base Rates	$ 773.63	$ 912.51	$ 634.75
PSA - Forward and Historical Components (4.0 mils)	34.65	38.51	30.79
PSA - Adjustor (3.987 mils)	34.54	38.39	30.69
Roll off of PSA - Adjustor (3.987 mils)	(34.54)	(38.39)	(30.69)
All Other Bill Components	47.10	52.34	41.84
Total without Interim Base Rate Surcharge	$ 855.38	$ 1,003.36	$ 707.38
Bill impact of Interim Base Rate Surcharge (1.63% on base)	**$ 12.61**	**$ 14.87**	**$ 10.35**

Industrial E34/35			
Average kWh per Month	4,008,132	4,176,596	3,839,667
Base Rates	$ 245,795.07	$ 256,684.48	$ 234,905.67
PSA - Forward and Historical Components (4.0 mils)	16,032.53	16,706.38	15,358.67
PSA - Adjustor (3.987 mils)	15,980.42	16,652.09	15,308.75
Roll off of PSA - Adjustor (3.987 mils)	(15,980.42)	(16,652.09)	(15,308.75)
All Other Bill Components	3,946.24	4,105.94	3,786.54
Total without Interim Base Rate Surcharge	$ 265,773.84	$ 277,496.80	$ 254,050.88
Bill impact of Interim Base Rate Surcharge (1.63% on base)	**$ 4,006.46**	**$ 4,183.96**	**$ 3,828.96**

Notes:

1) Bill excludes regulatory Assessment charge, taxes and fees, but their inclusion would not affect the bill impact due to the Interim Base Rate Surcharge.
2) Bill impact based on $42.4 million revenue requirements and adjusted test year base revenue of $2,637,447,000 less E-3/E-4 revenue plut E-36 revenue as shown below

Adjusted test year revenue	$	2,637,447
Less E-3 and E-4 revenue	$	(43,032)
Plus E-36 Revenue	$	3,606
Base revenue for interim base rate increase	$	2,598,021
Interim revenue requirements	$	42,400
% increase		1.63%

3) Interim Base Rate Surcharge would not be applied to E-3 and E-4 customers and would apply to E-36 customers

September 12, 2008

EXHIBIT
AECC-1
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

In the Matter of the Application of Arizona)
Public Service Company for a Hearing to)
Determine the Fair Value of the Utility)
Property of the Company for Ratemaking)
Purposes, to Fix a Just and Reasonable)
Rate of Return Thereon, to Approve Rate)
Schedules Designed to Develop Such Return)

Docket No. E-01345A-08-0172

Direct Testimony of Kevin C. Higgins

on behalf of

Freeport-McMoRan Copper & Gold Inc. and

Arizonans for Electric Choice & Competition

Interim Rates

August 29, 2008

BEFORE THE ARIZONA CORPORATION COMMISSION

In the Matter of the Application of Arizona) Public Service Company for a Hearing to) Determine the Fair Value of the Utility) Property of the Company for Ratemaking) Purposes, to Fix a Just and Reasonable) Rate of Return Thereon, to Approve Rate) Schedules Designed to Develop Such Return)	**Docket No. E-01345A-08-0172**

Direct Testimony of Kevin C. Higgins

on behalf of

Phelps Dodge Mining Company and

Arizonans for Electric Choice & Competition

Interim Rates

August 29, 2008

TABLE OF CONTENTS

DIRECT TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Freeport-McMoRan Copper & Gold Inc. and Arizonans for Electric Choice and Competition ("AECC"). AECC is a business coalition that advocates on behalf of retail electric customers in Arizona.[1]

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward the Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist

[1] Henceforth in this testimony, Freeport-McMoRan Copper & Gold Inc. and AECC collectively will be referred to as "AECC."

DIRECT TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Phelps Dodge Mining Company and Arizonans for Electric Choice and Competition ("AECC"). AECC is a business coalition that advocates on behalf of retail electric customers in Arizona.[1]

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward the Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

[1] Henceforth in this testimony, Phelps Dodge Mining Company and AECC collectively will be referred to as "AECC."

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you previously testified before this Commission?

A. Yes. I have testified in a number of proceedings before this Commission, including the generic proceeding on retail electric competition (1998),[2] the hearings on the Arizona Public Service Company ("APS") 1999 Settlement Agreement (1999),[3] the hearings on the Tucson Electric Power ("TEP") 1999 Settlement Agreement (1999),[4] the AEPCO transition charge hearings (1999),[5] the Commission's Track A proceeding (2002),[6] the APS adjustment mechanism proceeding (2003),[7] the Arizona ISA proceeding (2003),[8] the APS 2004 rate case (2004),[9] the Trico rate case (2005),[10] the TEP rate review (2005),[11] the APS interim rate proceeding (2006),[12] the APS 2006 rate case (2006),[13] TEP's request to amend Decision No. 62103 (2007),[14] and the TEP rate case (2008).[15]

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[2] Docket No. RE-00000C-94-0165.
[3] Docket Nos. RE-00000C-94-0165, E-01345A-98-0471, and E-01345A-98-0473.
[4] Docket Nos. RE-00000C-94-0165, E-01933A-97-0772, and E-01933A-97-0773.
[5] Docket No. E-01773A-98-0470.
[6] Docket Nos. E-00000A-02-0051; E-01345A-01-0822; E-00000A-01-0630; E-01933A-02-0069; E-01933A-98-0471.
[7] Docket No. E-01345A-02-0403.
[8] Docket No. E-00000A-01-0630.
[9] Docket No. E-01345A-03-0437.
[10] Docket No. E-01461A-04-0607.
[11] Docket No. E-01933A-04-0408.
[12] Docket No. E-01345A-06-0009.
[13] Docket No. E-01345A-05-0816.
[14] Docket No. E-01933A-05-0650.

Q. Have you testified before utility regulatory commissions in other states?

A. Yes. I have testified in over seventy other proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arkansas, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Utah, Virginia, Washington, West Virginia, and Wyoming. I have also participated in various Pricing Processes conducted by the Salt River Project Board and have filed affidavits in proceedings at the Federal Energy Regulatory Commission.

A more detailed description of my qualifications is contained in Attachment KCH-1, attached to this testimony.

Overview and Conclusions

Q. What is the purpose of your testimony in this proceeding?

A. My testimony addresses APS's request for an interim rate increase and recommends adjustments to the Company's proposal that I believe are necessary to ensure results that are just and reasonable.

Q. What conclusions have you reached in your analysis?

A. In light of the cash flow pressures being experienced by APS, I conclude that some interim rate relief is warranted to protect retail customers from the negative consequences of a credit downgrade, but the amount of relief needed is significantly less than the amount requested by the Company. Specifically, I

[15] Docket No. E-01933A-07-0402.

believe it is appropriate to grant an interim rate increase, subject to refund with interest, sufficient to permit APS to attain a Funds-from-Operations/Debt Ratio of 18.25 percent in 2009. I calculate that this ratio can be attained through an interim rate increase of $42.4 million on an annualized basis. This incremental revenue should be collected through an interim rate increase of no greater than 1.61 percent applied to base rates effective January 1, 2009.

<u>Need for Interim Increase</u>

Q. In your opinion, has APS demonstrated a need for an interim increase?

A. Yes. However, the amount needed is significantly less than APS has proposed. I agree with APS that it is very important to ensure that the Company does not experience a credit downgrade to below investment grade, as higher utility credit costs would have a negative impact on customers. For this reason, I believe it is prudent to provide interim relief to the extent that it is necessary to avoid a downgrade while APS's general rate case is pending.

Q. What amount of interim relief has APS requested?

APS has requested interim relief in the amount of $115 million on an annualized basis. This amount corresponds to the annual revenues produced by the 2007 PSA adjustor charge of $.003987 per kWh, which expired by its own terms in July 2008. Prior to that expiration, APS had proposed that the 2007 PSA adjustor charge be converted to an Interim Base Surcharge in the same amount.

Q. What is your general assessment of APS's proposal?

A. APS's proposal appears to have been driven by the administrative convenience of retaining the 2007 PSA adjustor charge. I believe this approach is flawed for two fundamental reasons: (1) there is no reason to believe that the amount recovered by the 2007 PSA adjustor charge would necessarily correspond to the amount of interim relief required (except by coincidence); and (2) the per kilowatt-hour PSA adjustor was levied for the specific purpose of recovering fuel and purchased power costs. This per-kWh charge is entirely inappropriate for the purpose of providing interim rate relief in this proceeding, as the Company's need for relief is driven by cost pressures unrelated to the cost of fuel and purchased power. Such a per-kWh charge falls disproportionately on higher-load-factor customers, and would result in an unreasonable burden on these customers in the context of providing interim rate relief.

Since filing its initial application, APS has supplemented its filing by presenting alternative rate designs for the requested interim recovery, which are discussed in the affidavit of David J. Rumolo filed July 11, 2008.

Q. What criteria should be used in evaluating the emergency request?

A. APS has emphasized that the Funds-from-Operations/Debt ratio ("FFO/Debt ratio") is the key financial metric examined by the credit agencies in establishing credit ratings.[16] APS has further indicated that a FFO/Debt ratio of 18 to 28 percent is necessary for a utility with APS's risk profile to maintain a BBB credit rating from Standard & Poor's ("S&P").[17] APS has projected that absent

[16] Affidavit of Donald E. Brandt, p. 3, lines 17-21.
[17] Ibid., p. 12, lines 10-11.

interim relief, its FFO/Debt ratio would fall to 17.6 percent in 2009.[18] Based on APS's representations regarding the importance of the FFO/Debt Ratio to its credit rating, I believe it is necessary to allow an interim rate increase sufficient to permit APS to attain a FFO/Debt ratio in excess of 18 percent in 2009, in order to prevent a credit downgrade.

Q. What specific recommendation do you make in this proceeding?

A. I recommend that interim relief should be granted sufficient to allow APS to meet an FFO/Debt ratio of 18.25 percent in 2009. This would allow APS to remain within the financial parameters required by credit agencies pending the outcome of its general rate case.

Q. How much revenue would APS require from an interim increase to attain a FFO/Debt ratio of 18.25 percent in 2009?

A. I calculate that this could be accomplished with an interim increase of $42.4 million effective January 1, 2009, which can be implemented through an equal percentage surcharge on base rates of 1.61 percent, using 2007 adjusted test year revenue. This percentage increase can be reduced slightly by adjusting for expected increases in 2009 revenue attributable to load growth. My calculations are shown in Attachment KCH-2.

Q. What is your recommendation to the Commission with respect to the amount of interim relief that should be granted to APS?

A. I recommend that the Commission grant APS interim relief sufficient to achieve an FFO/Debt Ratio of 18.25 percent in 2009. This interim relief should be

[18] Ibid., p. 12, lines 11-19.

subject to refund with interest pending the Commission's final decision in this docket. I calculate that this would require an increase in revenues of $42.4 million effective January 1, 2009, which should be recovered through an equal percentage surcharge of no greater than 1.61 percent on the base rate portion of customer bills. As I indicated above, this percentage increase should be reduced slightly by adjusting for 2009 load growth.

Q. Why do you believe your recommendation is reasonable?

A. As I stated above, it is very important to ensure that APS does not experience a credit downgrade to below investment grade, as higher utility credit costs will have a negative impact on customers. APS's application indicates that absent interim rate relief, there is a material probability that the Company's FFO/Debt ratio will fall below 18 percent in 2009. Such an event would increase the risk of a credit downgrade. I believe that providing interim relief sufficient to allow APS to attain a 2009 FFO/Debt ratio of 18 percent, plus a reasonable buffer, during the pendency of its general rate case, is reasonable and in the public interest.

Rate Design

Q. What rate design has APS proposed for its interim increase?

A. In its initial application, APS proposed a charge of $.003987 per kWh on all retail kWh except E-3 and E-4 low-income customers, E-36 customers, and rate schedules Solar-2 and SP-1. In a subsequent filing, APS presented two additional options: (1) an equal percentage increase applied to base rates, and (2) a hybrid option in which revenue requirements would be allocated to customer classes based on energy, but recovered within the customer classes through a demand charge from those customer classes billed on a demand basis.

Q. What is your assessment of these options?

A. Of the three options presented by APS, only the equal percentage increase is reasonable. This approach spreads the burden of the interim increase in a manner that is proportionate to current base rates. Absent a record to properly determine whether particular customer groups should bear different relative burdens, the only reasonable approach to spreading an interim rate increase is on an equal percentage basis. Therefore, my recommendation to the Commission is to recover any interim relief granted in this proceeding through an equal percentage increase applied to base rates, consistent with the option described by Mr. Rumolo on page 3, lines 16-21 of his affidavit.

In contrast, the first option presented by APS, a flat cents-per-kWh charge, would place a disproportionate burden on customers for whom energy costs constitute a relatively large proportion of their APS bills. Negatively-impacted customers include those with higher-load factors and customers taking service at higher voltage levels. This is shown in Table KCH-1, below. For example, at the amount of interim increase proposed by APS, a 75 percent load factor E-35 customer would experience a base rate increase in excess of 7.7 percent under a flat kWh charge – 75 percent higher than the 4.4 percent average increase identified by Mr. Rumolo.

Table KCH-1

Impact of Flat kWh Rate Design on
Commercial and Industrial Customers
@APS Requested Interim Increase

Average System Increase = 4.36%

Rate schedule	Customer size (kW)	Load Factor	Rate Impact
E-32	100	35%	3.65%
E-32	100	55%	4.62%
E-32	100	75%	5.28%
E-32	500	35%	4.14%
E-32	500	55%	5.11%
E-32	500	75%	5.74%
E-32	1000	35%	4.21%
E-32	1000	55%	5.18%
E-32	1000	75%	5.81%
E-34	5000	55%	6.21%
E-34	5000	75%	6.99%
E-35	5000	55%	6.88%
E-35	5000	75%	7.71%

There is no sound rationale for allocating an interim increase in this proceeding based on energy usage. The PSA mechanism already recovers projected changes in fuel and purchased power costs from customers on a flat per-kWh basis. Consequently, higher-load factor and higher voltage customers already pay a higher percentage increase than the system average when the PSA charges are levied. Further, because of this mechanism, we can safely conclude that APS's need for an interim increase is *not* the result of increases in fuel and purchased power expenses. Rather, it is largely attributable to the cash flow impacts of APS's increased investment in system infrastructure – a point that APS makes repeatedly in its application. The cost recovery mechanism for interim relief needs to reflect the general nature of the costs that are causing the need for an increase: a flat kWh charge does not accomplish this fundamental rate design objective.

The hybrid proposal presented by APS is merely a compromise between a cost recovery mechanism that is reasonable and one that is not. So while it produces customer impacts that are less unreasonable than the flat kWh charge, it is still "half wrong." Specifically, there is no basis in cost causation to allocate the interim increase to customer classes on an energy basis, as would occur in the first step under this approach.

Q. Based on your experience, is the equal percentage approach you are recommending a typical design when interim relief is granted?

A. Yes. I have participated in a number of rate proceedings in which interim rate relief was granted, and equal percentage approaches have been the norm.[19]

In 2000 and 2001, I participated in rate proceedings before the Utah Public Service Commission in which interim rate relief was requested. In 2000, the Utah Commission granted Questar Gas Company interim rate relief in the form of an equal percentage rider on the non-gas portion of retail customer bills.[20] Then in

[19] The only exceptions that I can recall are: (1) a 2001 Puget Sound Energy proceeding in which the Washington Commission approved a multi-party stipulation that resolved numerous issues in the concurrent general rate case. That settlement incorporated an interim rate increase that increased all billing components on an equal percentage basis after first allocating costs between residential and non-residential customers. [2001 Puget Sound Energy Interim Rate Case, Washington Utilities and Transportation Commission, Docket Nos. UE-011570 and UE-011571]; and (2) the previous APS rate case in which this Commission granted an interim PSA adjustor, discussed below.

[20] "In the Matter of the Application of Questar Gas Company for an Increase in Rates and Charges," Utah Public Service Commission, Docket No. 99-057-20.

2001, the Utah Public Service Commission granted PacifiCorp interim rate relief, again in the form of an equal percentage surcharge on all retail customers.[21]

In 2003-04, I testified in a Detroit Edison proceeding in Michigan in which interim relief was requested. In that case, I recommended, as did others, that any interim increase should be levied on an across-the-board equal percentage basis – the same recommendation I am making here. The equal-percentage approach was subsequently adopted by the Michigan Public Service Commission, subject to statutory rate caps for certain classes.[22]

In 2004, I participated in a rate proceeding in Alaska, in which interim rates also were adopted. In that case, the interim increase was also collected through an equal percentage increase on all billing components, with the exception of the customer charge.[23]

In 2006, I participated in an Xcel Energy general rate proceeding in Minnesota. In that case, interim rates were approved by the Minnesota Public Utilities Commission in the form of an across-the-board 7.25 percent surcharge on all customer bills.[24]

The consistency across these cases is clear: in awarding an interim rate increase, an equal percentage increase on all customers is very typical. Indeed,

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[21] "In the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulations," Utah Public Service Commission, Docket No. 01-35-01.
[22] "In the Matter of Application of the Detroit Edison Company to Increase Rates, Amend Its Rate Schedules Governing the Distribution and Supply of Electric Energy, etc.," Michigan Public Service Commission, Case No. U-13808.
[23] "In the Matter of the Application by Golden Valley Electric Association, Inc., for Authority to Implement Simplified Rate Filing Procedures and Adjust Rates," Regulatory Commission of Alaska, Docket No. U-4-33
[24] "In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota," Minnesota Public Utilities Commission, Docket No. E-002/GR-05-1428.

absent a record to properly determine that various customer groups should bear different burdens, it is the only reasonable approach to spreading an interim rate increase.

Q. Are you personally familiar with other situations in which rate spread is determined in the absence of a record regarding class cost-of-service?

A. Yes. In Colorado, it is not unusual for general rate cases to be conducted in two phases: the first phase addresses revenue requirement and the second phase addresses cost-of-service, rate spread, and rate design. Upon determination of the first phase of the case, but prior to the resolution of the second phase, any base rate change is implemented via an equal percentage rider on all customers. Again, this approach is the most reasonable one to take in the absence of a record on cost of service.

Similarly, in August 2008, the Utah Public Service Commission approved a revenue increase for Rocky Mountain Power prior to conducting the phase of the hearing that addresses cost-of-service, rate spread, and rate design issues. Appropriately, the Utah Commission adopted an equal percentage rider on all rate schedules during the pendency of the rate spread phase of the case.[25]

Q. How does your recommendation comport with this Commission's decision in Docket No. E-01345A-06-0009 in which APS was granted an interim rate increase that was recovered through an equal cents-per-kWh surcharge?

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[25] "In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge," Utah Public Service Commission, Docket No. 07-035-93.

A. In that proceeding, APS's interim relief was driven by rising fuel and purchased power costs. Accordingly, the interim increase awarded in that case was an interim PSA adjustor that was directed specifically to the recovery of fuel and purchased power costs. The facts in this proceeding are very different. Unlike the previous case, APS is now recovering its fuel and purchased power costs. The pressure on the Company's FFO/Debt Ratio is coming from costs that are unrelated to energy expense. As a result, interim relief, if it is granted, should not come in the form of an interim PSA adjustor, but as a surcharge applied to base rates. This change in circumstances calls for a different rate design for the surcharge, i.e., an equal percentage approach.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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Vitae

PROFESSIONAL EXPERIENCE

Principal, Energy Strategies, L.L.C., Salt Lake City, Utah, January 2000 to present. Responsible for energy-related economic and policy analysis, regulatory intervention, and strategic negotiation on behalf of industrial, commercial, and public sector interests. Previously Senior Associate, February 1995 to December 1999.

Adjunct Instructor in Economics, Westminster College, Salt Lake City, Utah, September 1981 to May 1982; September 1987 to May 1995. Taught in the economics and M.B.A. programs. Awarded Adjunct Professor of the Year, Gore School of Business, 1990-91.

Chief of Staff to the Chairman, Salt Lake County Board of Commissioners, Salt Lake City, Utah, January 1991 to January 1995. Senior executive responsibility for all matters of county government, including formulation and execution of public policy, delivery of approximately 140 government services, budget adoption and fiscal management (over $300 million), strategic planning, coordination with elected officials, and communication with consultants and media.

Assistant Director, Utah Energy Office, Utah Department of Natural Resources, Salt Lake City, Utah, August 1985 to January 1991. Directed the agency's resource development section, which provided energy policy analysis to the Governor, implemented state energy development policy, coordinated state energy data collection and dissemination, and managed energy technology demonstration programs. Position responsibilities included policy formulation and implementation, design and administration of energy technology demonstration programs, strategic management of the agency's interventions before the Utah Public Service Commission, budget preparation, and staff development. Supervised a staff of economists, engineers, and policy analysts, and served as lead economist on selected projects.

Utility Economist, Utah Energy Office, January 1985 to August 1985. Provided policy and economic analysis pertaining to energy conservation and resource development, with an emphasis on utility issues. Testified before the state Public Service Commission as an expert witness in cases related to the above.

Acting Assistant Director, Utah Energy Office, June 1984 to January 1985. Same responsibilities as Assistant Director identified above.

Research Economist, Utah Energy Office, October 1983 to June 1984. Provided economic analysis pertaining to renewable energy resource development and utility issues. Experience includes preparation of testimony, development of strategy, and appearance as an expert witness for the Energy Office before the Utah PSC.

Operations Research Assistant, Corporate Modeling and Operations Research Department, Utah Power and Light Company, Salt Lake City, Utah, May 1983 to September 1983. Primary area of responsibility: designing and conducting energy load forecasts.

Instructor in Economics, University of Utah, Salt Lake City, Utah, January 1982 to April 1983. Taught intermediate microeconomics, principles of macroeconomics, and economics as a social science.

Teacher, Vernon-Verona-Sherrill School District, Verona, New York, September 1976 to June 1978.

EDUCATION

Ph.D. Candidate, Economics, University of Utah (coursework and field exams completed, 1981).

> Fields of Specialization: Public Finance, Urban and Regional Economics, Economic Development, International Economics, History of Economic Doctrines.

Bachelor of Science, Education, State University of New York at Plattsburgh, 1976 (cum laude).

Danish International Studies Program, University of Copenhagen, 1975.

SCHOLARSHIPS AND FELLOWSHIPS

University Research Fellow, University of Utah, Salt Lake City, Utah 1982 to 1983.
Research Fellow, Institute of Human Resources Management, University of Utah, 1980 to 1982.
Teaching Fellow, Economics Department, University of Utah, 1978 to 1980.
New York State Regents Scholar, 1972 to 1976.

EXPERT TESTIMONY

"Verified Joint Petition of Duke Energy Indiana, Inc., Indianapolis Power & Light Company, Northern Indiana Public Service Company and Vectren Energy Delivery of Indiana, Inc. for Approval, if and to the Extent Required, of Certain Changes in Operations That Are Likely To Result from the Midwest Independent System Operator, Inc.'s Implementation of Revisions to Its Open Access Transmission and Energy Markets Tariff to Establish a Co-Optimized, Competitive Market for Energy and Ancillary Services Market; and for Timely Recovery of Costs Associated with Joint Petitioners' Participation in Such Ancillary Services Market," **Indiana** Utility Regulatory Commission, Cause No. 43426. Direct testimony submitted August 6, 2008.

"In The Matter of the Application of The Detroit Edison Company for Authority to Increase Its Rates, Amend Its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority," **Michigan** Public Service Commission, Case No. U-15244. Direct testimony submitted July 15, 2008. Rebuttal testimony submitted August 8, 2008.

"Portland General Electric General Rate Case Filing," Public Utility Commission of **Oregon,** Docket No. UE-197. Direct testimony submitted July 9, 2008.

"In the Matter of PacifiCorp, dba Pacific Power, 2009 Transition Adjustment Mechanism, Schedule 200, Cost-Based Supply Service," Public Utility Commission of **Oregon,** Docket No. UE-199. Reply testimony submitted June 23, 2008.

"2008 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-072300 and UG-072301. Response testimony submitted May 30, 2008. Cross-Answer testimony submitted July 3, 2008. Joint testimony in support of partial stipulations submitted July 3, 2008 (rate spread/rate design) and August 28, 2008 (revenue requirements).

"Verified Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission to Approve an Alternative Regulatory Plan Pursuant to the Ind. Code 8-1-2.5, Et Seq., for the Offering of Energy Efficiency Conservation, Demand Response, and Demand-Side Management Programs and Associated Rate Treatment Including Incentives Pursuant to a Revised Standard Contract Rider No. 66 in Accordance with Ind. Code 8-1-2.5-1Et Seq. and 8-1-2-42(a); Authority to Defer Program Costs Associated with Its Energy Efficiency Portfolio of Programs; Authority to Implement New and Enhanced Energy Efficiency Programs in Its Energy Efficiency Portfolio of Programs; and Approval of a Modification of the Fuel Adjustment Clause Earnings and Expense Tests," **Indiana** Utility Regulatory Commission, Cause No. 43374. Direct testimony submitted May 21, 2008.

"Cinergy Corp., Duke Energy Ohio, Inc., Cinergy Power Investments, Inc., Generating Facilities LLCs," **Federal Energy Regulatory Commission**, Docket No. EC-08-78-000. Affidavit filed May 14, 2008.

"Application of Entergy Gulf States, Inc. for Authority to Change Rates and to Reconcile Fuel Costs, Public Utility Commission of **Texas**, Docket No. 34800 [SOAH Docket No. 473-08-0334]. Direct testimony submitted April 11, 2008. Testimony withdrawn pursuant to stipulation.

"Central Illinois Light Company d/b/a AmerenCILCO Proposed General Increase in Electric Delivery Service Rates, Central Illinois Public Service Company d/b/a AmerenCIPS Proposed General Increase in Electric Delivery Service Rates, Illinois Power Company d/b/a/ AmerenIP Proposed General Increase in Electric Delivery Service Rates, Central Illinois Light Company d/b/a AmerenCILCO, Proposed General Increase in Gas Delivery Service Rates, Central Illinois Public Service Company d/b/a AmerenCIPS Proposed General Increase in Gas Delivery Service Rates, Illinois Power Company d/b/a/ AmerenIP Proposed General Increase in Gas Delivery Service Rates," **Illinois** Commerce Commission, Docket Nos. 07-0585, 07-0586, 07-0587, 07-0588, 07-0589, 07-0590. Direct testimony submitted March 14, 2008. Rebuttal testimony submitted April 8, 2008.

"In the Matter of the Application of Public Service Company of Colorado for Authority to Implement an Enhanced Demand Side Management Cost Adjustment Mechanism to Include Current Recovery and Incentives," **Colorado** Public Utilities Commission, Docket No. 07A-420E. Answer testimony submitted March 10, 2008. Cross examined April 25, 2008.

"An Investigation of the Energy and Regulatory Issues in Section 50 of Kentucky's 2007 Energy Act," **Kentucky** Public Service Commission, Administrative Case No. 2007-00477. Direct testimony submitted February 29, 2008. Supplemental direct testimony submitted April 1, 2008. Cross examined April 30, 2008.

In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of Its Operations throughout the State of Arizona, **Arizona** Corporation Commission, Docket No. E-01933A-07-0402. Direct testimony submitted February 29, 2008 (revenue requirement), March 14, 2008 (rate design), and June 12, 2008 (settlement agreement). Cross examined July 14, 2008.

"Commonwealth Edison Company Proposed General Increase in Electric Rates," **Illinois** Commerce Commission, Docket No. 07-0566. Direct testimony submitted February 11, 2008. Rebuttal testimony submitted April 8, 2008.

"In the Matter of the Application of Questar Gas Company to File a General Rate Case," **Utah**

Public Service Commission, Docket No. 07-057-13. Direct testimony submitted January 28, 2008 (test period), March 31, 2008 (rate of return), April 21, 2008 (revenue requirement), and August 18, 2008 (cost of service, rate spread, rate design). Surrebuttal testimony submitted May 12, 2008 (rate of return). Cross examined February 8, 2008 (test period) and May 21, 2008 (rate of return).

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge," **Utah** Public Service Commission, Docket No. 07-035-93. Direct testimony submitted January 25, 2008 (test period), April 7, 2008 (revenue requirement), and July 21, 2008 (cost of service, rate design). Surrebuttal testimony submitted May 23, 2008 (revenue requirement). Cross examined February 7, 2008 (test period).

"In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Increase Rates for Distribution Service, Modify Certain Accounting Practices and for Tariff Approvals," Public Utilities Commission of **Ohio**, Case Nos. 07-551-EL-AIR, 07-552-EL-ATA, 07-553-EL-AAM, and 07-554-EL-UNC. Direct testimony submitted January 10, 2008.

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Wyoming, Consisting of a General Rate Increase of Approximately $36.1 Million per Year, and for Approval of a New Renewable Resource Mechanism and Marginal Cost Pricing Tariff," **Wyoming** Public Service Commission, Docket No. 20000-277-ER-07. Direct testimony submitted January 7, 2008. Cross examined March 6, 2008.

"In the Matter of the Application of Idaho Power Company for Authority to Increase Its Rates and Charges for Electric Service to Electric Customers in the State of Idaho," **Idaho** Public Utilities Commission, Case No. IPC-E-07-8. Direct testimony submitted December 10, 2007. Cross examined January 23, 2008.

"In The Matter of the Application of Consumers Energy Company for Authority to Increase Its Rates for the Generation and Distribution Of Electricity and Other Relief," **Michigan** Public Service Commission, Case No. U-15245. Direct testimony submitted November 6, 2007. Rebuttal testimony submitted November 20, 2007.

"In the Matter of Montana-Dakota Utilities Co., Application for Authority to Establish Increased Rates for Electric Service," **Montana** Public Service Commission, Docket No. D2007.7.79. Direct testimony submitted October 24, 2007.

"In the Matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 334," **New Mexico** Public Regulation Commission, Case No. 07-0077-UT. Direct testimony submitted October 22, 2007. Rebuttal testimony submitted November 19, 2007. Cross examined December 12, 2007.

"In The Matter of Georgia Power Company's 2007 Rate Case," **Georgia** Public Service Commission, Docket No. 25060-U. Direct testimony submitted October 22, 2007. Cross examined November 7, 2007.

"In the Matter of the Application of Rocky Mountain Power for an Accounting Order to Defer the Costs Related to the MidAmerican Energy Holdings Company Transaction," **Utah** Public Service Commission, Docket No. 07-035-04; "In the Matter of the Application of Rocky Mountain Power, a Division of PacifiCorp, for a Deferred Accounting Order To Defer the Costs of Loans Made to Grid West, the Regional Transmission Organization," Docket No. 06-035-163; "In the Matter of the Application of Rocky Mountain Power for an Accounting Order for Costs related to the Flooding of the Powerdale Hydro Facility," Docket No. 07-035-14. Direct testimony submitted September 10, 2007. Surrebuttal testimony submitted October 22, 2007. Cross examined October 30, 2007.

"In the Matter of General Adjustment of Electric Rates of East Kentucky Power Cooperative, Inc.," **Kentucky** Public Service Commission, Case No. 2006-00472. Direct testimony submitted July 6, 2007. Supplemental direct testimony submitted March 14, 2008.

"In the Matter of the Application of Sempra Energy Solutions for a Certificate of Convenience and Necessity for Competitive Retail Electric Service," **Arizona** Corporation Commission, Docket No. E-03964A-06-0168. Direct testimony submitted July 3, 2007. Rebuttal testimony submitted January 17, 2008.

"Application of Public Service Company of Oklahoma for a Determination that Additional Electric Generating Capacity Will Be Used and Useful," **Oklahoma** Corporation Commission, Cause No. PUD 200500516; "Application of Public Service Company of Oklahoma for a Determination that Additional Baseload Electric Generating Capacity Will Be Used and Useful," Cause No. PUD 200600030; "In the Matter of the Application of Oklahoma Gas and Electric Company for an Order Granting Pre-Approval to Construct Red Rock Generating Facility and Authorizing a Recovery Rider," Cause No. PUD200700012. Responsive testimony submitted May 21, 2007. Cross examined July 26, 2007.

"Application of Nevada Power Company for Authority to Increase Its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers and for Relief Properly Related Thereto," Public Utilities Commission of **Nevada**, Docket No. 06-11022.

Direct testimony submitted March 14, 2007 (Phase III – revenue requirements) and March 19, 2007 (Phase IV – rate design). Cross examined April 10, 2007 (Phase III – revenue requirements) and April 16, 2007 (Phase IV – rate design).

"In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service," **Arkansas** Public Service Commission, Docket No. 06-101-U. Direct testimony submitted February 5, 2007. Surrebuttal testimony submitted March 26, 2007.

"Monongahela Power Company and The Potomac Edison Company, both d/b/a Allegheny Power – Rule 42T Application to Increase Electric Rates and Charges," Public Service Commission of **West Virginia**, Case No. 06-0960-E-42T; "Monongahela Power Company and The Potomac Edison Company, both d/b/a Allegheny Power – Information Required for Change of Depreciation Rates Pursuant to Rule 20," Case No. 06-1426-E-D. Direct and rebuttal testimony submitted January 22, 2007.

"In the Matter of the Tariffs of Aquila, Inc., d/b/a Aquila Networks-MPS and Aquila Networks-L&P Increasing Electric Rates for the Services Provided to Customers in the Aquila Networks-MPS and Aquila Networks-L&P Missouri Service Areas," **Missouri** Public Service Commission, Case No. ER-2007-0004. Direct testimony submitted January 18, 2007 (revenue requirements) and January 25, 2007 (revenue apportionment). Supplemental direct testimony submitted February 27, 2007.

"In the Matter of the Filing by Tucson Electric Power Company to Amend Decision No. 62103, **Arizona** Corporation Commission, Docket No. E-01933A-05-0650. Direct testimony submitted January 8, 2007. Surrebuttal testimony filed February 8, 2007. Cross examined March 8, 2007.

"In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area," **Missouri** Public Service Commission, Case No. ER-2007-0002. Direct testimony submitted December 15, 2006 (revenue requirements) and December 29, 2006 (fuel adjustment clause/cost-of-service/rate design). Rebuttal testimony submitted February 5, 2007 (cost-of-service). Surrebuttal testimony submitted February 27, 2007. Cross examined March 21, 2007.

"In the Matter of Application of The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky, Inc. for an Adjustment of Electric Rates," **Kentucky** Public Service Commission, Case No. 2006-00172. Direct testimony submitted September 13, 2006.

"In the Matter of Appalachian Power Company's Application for Increase in Electric Rates," **Virginia** State Corporation Commission, Case No. PUE-2006-00065. Direct testimony submitted September 1, 2006. Cross examined December 7, 2006.

"In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, To Approve Rate Schedules Designed to Develop Such Return, and to Amend Decision No. 67744, **Arizona** Corporation Commission," Docket No. E-01345A-05-0816. Direct testimony submitted August 18, 2006 (revenue requirements) and September 1, 2006 (cost-of-service/rate design). Surrebuttal testimony submitted September 27, 2006. Cross examined November 7, 2006.

"Re: The Tariff Sheets Filed by Public Service Company of Colorado with Advice Letter No 1454 – Electric," **Colorado** Public Utilities Commission, Docket No. 06S-234EG. Answer testimony submitted August 18, 2006.

"Portland General Electric General Rate Case Filing," Public Utility Commission of **Oregon,** Docket No. UE-180. Direct testimony submitted August 9, 2006. Joint testimony regarding stipulation submitted August 22, 2006.

"2006 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-060266 and UG-060267. Response testimony submitted July 19, 2006. Joint testimony regarding stipulation submitted August 23, 2006.

"In the Matter of PacifiCorp, dba Pacific Power & Light Company, Request for a General Rate Increase in the Company's Oregon Annual Revenues," Public Utility Commission of **Oregon**, Docket No. UE-179. Direct testimony submitted July 12, 2006. Joint testimony regarding stipulation submitted August 21, 2006.

"Petition of Metropolitan Edison Company for Approval of a Rate Transition Plan," **Pennsylvania** Public Utilities Commission, Docket Nos. P-00062213 and R-00061366; "Petition of Pennsylvania Electric Company for Approval of a Rate Transition Plan," Docket Nos. P-0062214 and R-00061367; Merger Savings Remand Proceeding, Docket Nos. A-110300F0095 and A-110400F0040. Direct testimony submitted July 10, 2006. Rebuttal testimony submitted August 8, 2006. Surrebuttal testimony submitted August 18, 2006. Cross examined August 30, 2006.

"In the Matter of the Application of PacifiCorp for approval of its Proposed Electric Rate Schedules & Electric Service Regulations," **Utah** Public Service Commission, Docket No. 06-035-21. Direct testimony submitted June 9, 2006 (Test Period). Surrebuttal testimony submitted July 14, 2006.

"Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for the Approval of the Conservation Enabling Tariff Adjustment Option and Accounting Orders," **Utah** Public Service Commission, Docket No. 05-057-T01. Direct testimony submitted

May 15, 2006. Rebuttal testimony submitted August 8, 2007. Cross examined September 19, 2007.

"Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, Illinois Power Company d/b/a AmerenIP, Proposed General Increase in Rates for Delivery Service (Tariffs Filed December 27, 2005)," **Illinois** Commerce Commission, Docket Nos. 06-0070, 06-0071, 06-0072. Direct testimony submitted March 26, 2006. Rebuttal testimony submitted June 27, 2006.

"In the Matter of Appalachian Power Company and Wheeling Power Company, both dba American Electric Power," Public Service Commission of **West Virginia**, Case No. 05-1278-E-PC-PW-42T. Direct and rebuttal testimony submitted March 8, 2006.

"In the Matter of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota," **Minnesota** Public Utilities Commission, Docket No. G-002/GR-05-1428. Direct testimony submitted March 2, 2006. Rebuttal testimony submitted March 30, 2006. Cross examined April 25, 2006.

"In the Matter of the Application of Arizona Public Service Company for an Emergency Interim Rate Increase and for an Interim Amendment to Decision No. 67744," **Arizona** Corporation Commission, Docket No. E-01345A-06-0009. Direct testimony submitted February 28, 2006. Cross examined March 23, 2006.

"In the Matter of the Applications of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in Their Charges for Electric Service," State Corporation Commission of **Kansas**, Case No. 05-WSEE-981-RTS. Direct testimony submitted September 9, 2005. Cross examined October 28, 2005.

"In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Recover Costs Associated with the Construction and Ultimate Operation of an Integrated Combined Cycle Electric Generating Facility," Public Utilities Commission of **Ohio**," Case No. 05-376-EL-UNC. Direct testimony submitted July 15, 2005. Cross examined August 12, 2005.

"In the Matter of the Filing of General Rate Case Information by Tucson Electric Power Company Pursuant to Decision No. 62103," **Arizona** Corporation Commission, Docket No. E-01933A-04-0408. Direct testimony submitted June 24, 2005.

"In the Matter of Application of The Detroit Edison Company to Unbundle and Realign Its Rate Schedules for Jurisdictional Retail Sales of Electricity," **Michigan** Public Service Commission, Case No. U-14399. Direct testimony submitted June 9, 2005. Rebuttal testimony submitted July 1, 2005.

"In the Matter of the Application of Consumers Energy Company for Authority to Increase Its Rates for the Generation and Distribution of Electricity and Other Relief," **Michigan** Public Service Commission, Case No. U-14347. Direct testimony submitted June 3, 2005. Rebuttal testimony submitted June 17, 2005.

"In the Matter of Pacific Power & Light, Request for a General Rate Increase in the Company's Oregon Annual Revenues," Public Utility Commission of **Oregon**, Docket No. UE 170. Direct testimony submitted May 9, 2005. Surrebuttal testimony submitted June 27, 2005. Joint testimony regarding partial stipulations submitted June 2005, July 2005, and August 2005.

"In the Matter of the Application of Trico Electric Cooperative, Inc. for a Rate Increase," **Arizona** Corporation Commission, Docket No. E-01461A-04-0607. Direct testimony submitted April 13, 2005. Surrebuttal testimony submitted May 16, 2005. Cross examined May 26, 2005.

"In the Matter of the Application of PacifiCorp for Approval of its Proposed Electric Service Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 04-035-42. Direct testimony submitted January 7, 2005.

"In the Matter of the Application by Golden Valley Electric Association, Inc., for Authority to Implement Simplified Rate Filing Procedures and Adjust Rates," Regulatory Commission of **Alaska**, Docket No. U-4-33. Direct testimony submitted November 5, 2004. Cross examined February 8, 2005.

"Advice Letter No. 1411 - Public Service Company of Colorado Electric Phase II General Rate Case," **Colorado** Public Utilities Commission, Docket No. 04S-164E. Direct testimony submitted October 12, 2004. Cross-answer testimony submitted December 13, 2004. Testimony withdrawn January 18, 2005, following Applicant's withdrawal of testimony pertaining to TOU rates.

"In the Matter of Georgia Power Company's 2004 Rate Case," **Georgia** Public Service Commission, Docket No. 18300-U. Direct testimony submitted October 8, 2004. Cross examined October 27, 2004.

"2004 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-040641 and UG-040640. Response testimony submitted September 23, 2004. Cross-answer testimony submitted November 3, 2004. Joint testimony regarding stipulation submitted December 6, 2004.

"In the Matter of the Application of PacifiCorp for an Investigation of Interjurisdictional Issues," **Utah** Public Service Commission, Docket No. 02-035-04. Direct testimony submitted July 15, 2004. Cross examined July 19, 2004.

"In the Matter of an Adjustment of the Gas and Electric Rates, Terms and Conditions of Kentucky Utilities Company," **Kentucky** Public Service Commission, Case No. 2003-00434. Direct testimony submitted March 23, 2004. Testimony withdrawn pursuant to stipulation entered May 2004.

"In the Matter of an Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company," **Kentucky** Public Service Commission, Case No. 2003-00433. Direct testimony submitted March 23, 2004. Testimony withdrawn pursuant to stipulation entered May 2004.

"In the Matter of the Application of Idaho Power Company for Authority to Increase Its Interim and Base Rates and Charges for Electric Service," **Idaho** Public Utilities Commission, Case No. IPC-E-03-13. Direct testimony submitted February 20, 2004. Rebuttal testimony submitted March 19, 2004. Cross examined April 1, 2004.

"In the Matter of the Applications of the Ohio Edison Company, the Cleveland Electric Illuminating Company and the Toledo Edison Company for Authority to Continue and Modify Certain Regulatory Accounting Practices and Procedures, for Tariff Approvals and to Establish Rates and Other Charges, Including Regulatory Transition Charges Following the Market Development Period," Public Utilities Commission of **Ohio**, Case No. 03-2144-EL-ATA. Direct testimony submitted February 6, 2004. Cross examined February 18, 2004.

"In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, To Fix a Just and Reasonable Rate of Return Thereon, To Approve Rate Schedules Designed to Develop Such Return, and For Approval of Purchased Power Contract," **Arizona** Corporation Commission, Docket No. E-01345A-03-0437. Direct testimony submitted February 3, 2004. Rebuttal testimony submitted March 30, 2004. Direct testimony regarding stipulation submitted September 27, 2004. Responsive / Clarifying testimony regarding stipulation submitted October 25, 2004. Cross examined November 8-10, 2004 and November 29-December 3, 2004.

"In the Matter of Application of the Detroit Edison Company to Increase Rates, Amend Its Rate Schedules Governing the Distribution and Supply of Electric Energy, etc.," **Michigan** Public Service Commission, Case No. U-13808. Direct testimony submitted December 12, 2003 (interim request) and March 5, 2004 (general rate case).

"In the Matter of PacifiCorp's Filing of Revised Tariff Schedules," Public Utility Commission of **Oregon**, Docket No. UE-147. Joint testimony regarding stipulation submitted August 21, 2003.

"Petition of PSI Energy, Inc. for Authority to Increase Its Rates and Charges for Electric Service, etc.," **Indiana** Utility Regulatory Commission, Cause No. 42359. Direct testimony submitted August 19, 2003. Cross examined November 5, 2003.

"In the Matter of the Application of Consumers Energy Company for a Financing Order Approving the Securitization of Certain of its Qualified Cost," **Michigan** Public Service Commission, Case No. U-13715. Direct testimony submitted April 8, 2003. Cross examined April 23, 2003.

"In the Matter of the Application of Arizona Public Service Company for Approval of Adjustment Mechanisms," **Arizona** Corporation Commission, Docket No. E-01345A-02-0403. Direct testimony submitted February 13, 2003. Surrebuttal testimony submitted March 20, 2003. Cross examined April 8, 2003.

"Re: The Investigation and Suspension of Tariff Sheets Filed by Public Service Company of Colorado, Advice Letter No. 1373 – Electric, Advice Letter No. 593 – Gas, Advice Letter No. 80 – Steam," **Colorado** Public Utilities Commission, Docket No. 02S-315 EG. Direct testimony submitted November 22, 2002. Cross-answer testimony submitted January 24, 2003.

"In the Matter of the Application of The Detroit Edison Company to Implement the Commission's Stranded Cost Recovery Procedure and for Approval of Net Stranded Cost Recovery Charges," **Michigan** Public Service Commission, Case No. U-13350. Direct testimony submitted November 12, 2002.

"Application of South Carolina Electric & Gas Company: Adjustments in the Company's Electric Rate Schedules and Tariffs," Public Service Commission of **South Carolina**, Docket No. 2002-223-E. Direct testimony submitted November 8, 2002. Surrebuttal testimony submitted November 18, 2002. Cross examined November 21, 2002.

"In the Matter of the Application of Questar Gas Company for a General Increase in Rates and Charges," **Utah** Public Service Commission, Docket No. 02-057-02. Direct testimony submitted August 30, 2002. Rebuttal testimony submitted October 4, 2002.

"The Kroger Co. v. Dynegy Power Marketing, Inc.," **Federal Energy Regulatory Commission**, EL02-119-000. Confidential affidavit filed August 13, 2002.

"In the matter of the application of Consumers Energy Company for determination of net stranded costs and for approval of net stranded cost recovery charges," **Michigan** Public Service

Commission, Case No. U-13380. Direct testimony submitted August 9, 2002. Rebuttal testimony submitted August 30, 2002. Cross examined September 10, 2002.

"In the Matter of the Application of Public Service Company of Colorado for an Order to Revise Its Incentive Cost Adjustment," **Colorado** Public Utilities Commission, Docket 02A-158E. Direct testimony submitted April 18, 2002.

"In the Matter of the Generic Proceedings Concerning Electric Restructuring Issues," **Arizona** Corporation Commission, Docket No. E-00000A-02-0051, "In the Matter of Arizona Public Service Company's Request for Variance of Certain Requirements of A.A.C. R14-2-1606," Docket No. E-01345A-01-0822, "In the Matter of the Generic Proceeding Concerning the Arizona Independent Scheduling Administrator," Docket No. E-00000A-01-0630, "In the Matter of Tucson Electric Power Company's Application for a Variance of Certain Electric Competition Rules Compliance Dates," Docket No. E-01933A-02-0069, "In the Matter of the Application of Tucson Electric Power Company for Approval of its Stranded Cost Recovery," Docket No. E-01933A-98-0471. Direct testimony submitted March 29, 2002 (APS variance request); May 29, 2002 (APS Track A proceeding/market power issues); and July 28, 2003 (Arizona ISA). Rebuttal testimony submitted August 29, 2003 (Arizona ISA). Cross examined June 21, 2002 (APS Track A proceeding/market power issues) and September 12, 2003 (Arizona ISA).

"In the Matter of Savannah Electric & Power Company's 2001 Rate Case," **Georgia** Public Service Commission, Docket No. 14618-U. Direct testimony submitted March 15, 2002. Cross examined March 28, 2002.

"Nevada Power Company's 2001 Deferred Energy Case," Public Utilities Commission of **Nevada,** PUCN 01-11029. Direct testimony submitted February 7, 2002. Cross examined February 21, 2002.

"2001 Puget Sound Energy Interim Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-011570 and UE-011571. Direct testimony submitted January 30, 2002. Cross examined February 20, 2002.

"In the Matter of Georgia Power Company's 2001 Rate Case," **Georgia** Public Service Commission, Docket No. 14000-U. Direct testimony submitted October 12, 2001. Cross examined October 24, 2001.

"In the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 01-35-01. Direct testimony submitted June 15, 2001. Rebuttal testimony submitted August 31, 2001.

"In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149," Public Utility Commission of **Oregon**, Docket No. UE-115. Direct testimony submitted February 20, 2001. Rebuttal testimony submitted May 4, 2001. Joint testimony regarding stipulation submitted July 27, 2001.

"In the Matter of the Application of APS Energy Services, Inc. for Declaratory Order or Waiver of the Electric Competition Rules," **Arizona** Corporation Commission, Docket No.E-01933A-00-0486. Direct testimony submitted July 24, 2000.

"In the Matter of the Application of Questar Gas Company for an Increase in Rates and Charges," **Utah** Public Service Commission, Docket No. 99-057-20. Direct testimony submitted April 19, 2000. Rebuttal testimony submitted May 24, 2000. Surrebuttal testimony submitted May 31, 2000. Cross examined June 6 & 8, 2000.

"In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1729-EL-ETP; "In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1730-EL-ETP. Direct testimony prepared, but not submitted pursuant to settlement agreement effected May 2, 2000.

"In the Matter of the Application of FirstEnergy Corp. on Behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company for Approval of Their Transition Plans and for Authorization to Collect Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1212-EL-ETP. Direct testimony prepared, but not submitted pursuant to settlement agreement effected April 11, 2000.

"2000 Pricing Process," **Salt River Project** Board of Directors, oral comments provided March 6, 2000 and April 10, 2000.

"Tucson Electric Power Company vs. Cyprus Sierrita Corporation," **Arizona** Corporation Commission, Docket No. E-000001-99-0243. Direct testimony submitted October 25, 1999. Cross examined November 4, 1999.

"Application of Hildale City and Intermountain Municipal Gas Association for an Order Granting Access for Transportation of Interstate Natural Gas over the Pipelines of Questar Gas Company for Hildale, Utah," **Utah** Public Service Commission, Docket No. 98-057-01. Rebuttal testimony submitted August 30, 1999.

"In the Matter of the Application by Arizona Electric Power Cooperative, Inc. for Approval of Its Filing as to Regulatory Assets and Transition Revenues," **Arizona** Corporation Commission, Docket No. E-01773A-98-0470. Direct testimony submitted July 30, 1999. Cross examined February 28, 2000.

"In the Matter of the Application of Tucson Electric Power Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01933A-98-0471; "In the Matter of the Filing of Tucson Electric Power Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01933A-97-0772; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted June 30, 1999. Rebuttal testimony submitted August 6, 1999. Cross examined August 11-13, 1999.

"In the Matter of the Application of Arizona Public Service Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01345A-98-0473; "In the Matter of the Filing of Arizona Public Service Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01345A-97-0773; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted June 4, 1999. Rebuttal testimony submitted July 12, 1999. Cross examined July 14, 1999.

"In the Matter of the Application of Tucson Electric Power Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01933A-98-0471; "In the Matter of the Filing of Tucson Electric Power Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01933A-97-0772; "In the Matter of the Application of Arizona Public Service Company for Approval of its Plan for Stranded Cost Recovery," Docket No. E-01345A-98-0473; "In the Matter of the Filing of Arizona Public Service Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01345A-97-0773; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted November 30, 1998.

"Hearings on Pricing," **Salt River Project** Board of Directors, written and oral comments provided November 9, 1998.

"Hearings on Customer Choice," **Salt River Project** Board of Directors, written and oral comments provided June 22, 1998; June 29, 1998; July 9, 1998; August 7, 1998; and August 14, 1998.

"In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," **Arizona** Corporation Commission, Docket No. U-0000-94-165. Direct and rebuttal testimony filed January 21, 1998. Second rebuttal testimony filed February 4, 1998. Cross examined February 25, 1998.

"In the Matter of Consolidated Edison Company of New York, Inc.'s Plans for (1) Electric Rate/Restructuring Pursuant to Opinion No. 96-12; and (2) the Formation of a Holding Company Pursuant to PSL, Sections 70, 108, and 110, and Certain Related Transactions," **New York** Public Service Commission, Case 96-E-0897. Direct testimony filed April 9, 1997. Cross examined May 5, 1997.

"In the Matter of the Petition of Sunnyside Cogeneration Associates for Enforcement of Contract Provisions," **Utah** Public Service Commission, Docket No. 96-2018-01; "In the Matter of the Application of Rocky Mountain Power for an Order Approving an Amendment to Its Power Purchase Agreement with Sunnyside Cogeneration Associates," Docket Nos. 05-035-46, and 07-035-99. Direct testimony submitted July 8, 1996. Oral testimony provided March 18, 2008.

"In the Matter of the Application of PacifiCorp, dba Pacific Power & Light Company, for Approval of Revised Tariff Schedules and an Alternative Form of Regulation Plan," **Wyoming** Public Service Commission, Docket No. 2000-ER-95-99. Direct testimony submitted April 8, 1996.

"In the Matter of the Application of Mountain Fuel Supply Company for an Increase in Rates and Charges," **Utah** Public Service Commission, Case No. 95-057-02. Direct testimony submitted June 19, 1995. Rebuttal testimony submitted July 25, 1995. Surrebuttal testimony submitted August 7, 1995.

"In the Matter of the Investigation of the Reasonableness of the Rates and Tariffs of Mountain Fuel Supply Company," **Utah** Public Service Commission, Case No. 89-057-15. Direct testimony submitted July 1990. Surrebuttal testimony submitted August 1990.

"In the Matter of the Review of the Rates of Utah Power and Light Company pursuant to The Order in Case No. 87-035-27," **Utah** Public Service Commission, Case No. 89-035-10. Rebuttal testimony submitted November 15, 1989. Cross examined December 1, 1989 (rate schedule changes for state facilities).

"In the Matter of the Application of Utah Power & Light Company and PC/UP&L Merging Corp. (to be renamed PacifiCorp) for an Order Authorizing the Merger of Utah Power & Light Company and PacifiCorp into PC/UP&L Merging Corp. and Authorizing the Issuance of Securities, Adoption of Tariffs, and Transfer of Certificates of Public Convenience and Necessity and Authorities in Connection Therewith," **Utah** Public Service Commission, Case No. 87-035-27; Direct testimony submitted April 11, 1988. Cross examined May 12, 1988 (economic impact of UP&L merger with PacifiCorp).

"In the Matter of the Application of Mountain Fuel Supply Company for Approval of Interruptible Industrial Transportation Rates," **Utah** Public Service Commission, Case No. 86-057-07. Direct testimony submitted January 15, 1988. Cross examined March 30, 1988.

"In the Matter of the Application of Utah Power and Light Company for an Order Approving a Power Purchase Agreement," **Utah** Public Service Commission, Case No. 87-035-18. Oral testimony delivered July 8, 1987.

"Cogeneration: Small Power Production," **Federal Energy Regulatory Commission**, Docket No. RM87-12-000. Statement on behalf of State of Utah delivered March 27, 1987, in San Francisco.

"In the Matter of the Investigation of Rates for Backup, Maintenance, Supplementary, and Standby Power for Utah Power and Light Company," **Utah** Public Service Commission, Case No. 86-035-13. Direct testimony submitted January 5, 1987. Case settled by stipulation approved August 1987.

"In the Matter of the Application of Sunnyside Cogeneration Associates for Approval of the Cogeneration Power Purchase Agreement," **Utah** Public Service Commission, Case No. 86-2018-01. Rebuttal testimony submitted July 16, 1986. Cross examined July 17, 1986.

"In the Matter of the Investigation of Demand-Side Alternatives to Capacity Expansion for Electric Utilities," **Utah** Public Service Commission, Case No. 84-999-20. Direct testimony submitted June 17, 1985. Rebuttal testimony submitted July 29, 1985. Cross examined August 19, 1985.

"In the Matter of the Implementation of Rules Governing Cogeneration and Small Power Production in Utah," **Utah** Public Service Commission, Case No. 80-999-06, pp. 1293-1318. Direct testimony submitted January 13, 1984 (avoided costs), May 9, 1986 (security for levelized contracts) and November 17, 1986 (avoided costs). Cross-examined February 29, 1984 (avoided costs), April 11, 1985 (standard form contracts), May 22-23, 1986 (security for levelized contracts) and December 16-17, 1986 (avoided costs).

OTHER RELATED ACTIVITY

Participant, Oregon Direct Access Task Force (UM 1081), May 2003 to November 2003.

Participant, Michigan Stranded Cost Collaborative, March 2003 to March 2004.

Member, Arizona Electric Competition Advisory Group, December 2002 to present.

Board of Directors, ex-officio, Desert STAR RTO, September 1999 to February 2002.

Member, Advisory Committee, Desert STAR RTO, September 1999 to February 2002. Acting Chairman, October 2000 to February 2002.

Board of Directors, Arizona Independent Scheduling Administrator Association, October 1998 to present.

Acting Chairman, Operating Committee, Arizona Independent Scheduling Administrator Association, October 1998 to June 1999.

Member, Desert Star ISO Investigation Working Groups: Operations, Pricing, and Governance, April 1997 to December 1999. Legal & Negotiating Committee, April 1999 to December 1999.

Participant, Independent System Operator and Spot Market Working Group, Arizona Corporation Commission, April 1997 to September 1997.

Participant, Unbundled Services and Standard Offer Working Group, Arizona Corporation Commission, April 1997 to October 1997.

Participant, Customer Selection Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Stranded Cost Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Electric System Reliability & Safety Working Group, Arizona Corporation Commission, November 1996 to September 1998.

Chairman, Salt Palace Renovation and Expansion Committee, Salt Lake County/State of Utah/Salt Lake City, multi-government entity responsible for implementation of planning, design, finance, and construction of an $85 million renovation of the Salt Palace Convention Center, Salt Lake City, Utah, May 1991 to December 1994.

State of Utah Representative, Committee on Regional Electric Power Cooperation, a joint effort of the Western Interstate Energy Board and the Western Conference of Public Service Commissioners, January 1987 to December 1990.

Member, Utah Governor's Economic Coordinating Committee, January 1987 to December 1990.

Chairman, Standard Contract Task Force, established by Utah Public Service Commission to address contractual problems relating to qualifying facility sales under PURPA, March 1986 to December 1990.

Chairman, Load Management and Energy Conservation Task Force, Utah Public Service Commission, August 1985 to December 1990.

Alternate Delegate for Utah, Western Interstate Energy Board, Denver, Colorado, August 1985 to December 1990.

Articles Editor, Economic Forum, September 1980 to August 1981.

Interim Increase Needed to Achieve 18.25% FFO/Debt Ratio in 2009
($000)

Ln No.	Income Statement *APS - Total Company*	Year 2009	Source
1	**PRESENT (CURRENT) REVENUES**	3,131,036	See Note 1
2	**AECC PROPOSED INTERIM RATE REVENUE CHANGE**	42,362	AECC Input
3	**TOTAL REVENUE**	3,173,398	Ln. 1 + Ln. 2
4	**Total Cost of Revenues**	1,210,802	See Note 1
5	**GROSS MARGIN**	1,962,596	Ln. 3 - Ln. 4
6	**OTHER OPERATING EXPENSES**		
7	Operations and Maintenance	822,227	See Note 1
8	Depreciation & Amortization	410,447	See Note 1
9	Other Taxes	142,863	See Note 1
10	**Total Other Operating Expenses**	1,375,537	Ln. 7 + Ln. 8 + Ln. 9
11	**INTEREST AND OTHER EXPENSES**		
12	Interest Expense	196,979	See Note 1
13	AECC Interest Expense Adj.	(659)	AECC Adjustment
14	AFUDC Debt / Capitalized Interest	(19,263)	See Note 1
15	AFUDC Equity	(24,132)	See Note 1
16	Other (Income) Subtotal	(2,426)	See Note 1
17	Other Expense Subtotal	18,809	See Note 1
18	**INCOME BEFORE INCOME TAXES**	417,751	Ln. 5 - Ln. 10 - Sum (Ln. 12 : Ln. 17)
19	Income Taxes	133,056	See Note 1
20	AECC Income Tax Expense Adj.	16,933	AECC Adjustment
21	**NET INCOME**	267,762	Ln. 18 - Ln. 19 - Ln. 20

Note 1: Data Source - APS Response to ACC Staff Data Request No. 2.4 (Present Rates with No Interim DAK_WP1)

Interim Increase Needed to Achieve 18.25% FFO/Debt Ratio in 2009

($000)

Ln No.	Funds From Operations / Adjusted Average Total Debt	Year 2009	Source
	Funds From Operations (FFO)		
1	Adjusted Net Income	267,762	AECC Net Income Workpaper Ln. 21
2	Depreciation & Amortization	410,447	See Note 1
3	Nuclear Fuel	41,146	See Note 1
4	Deferred Tax	46,241	See Note 1
5	Uncertain Tax Positions	0	See Note 1
6	Deferred Fuel (Excludes MTM)	3,484	See Note 1
7	Interest on Deferred Fuel	69	See Note 1
8	AFUDC Debt / Capitalized Interest	(19,263)	See Note 1
9	AFUDC	(24,132)	See Note 1
10	Imputed PPA Depreciation - SRP	9,055	See Note 1
11	Imputed PPA Depreciation - 2005 Reliability	7,514	See Note 1
12	Imputed PPA Depreciation - Renewable	0	See Note 1
13	Imputed PPA Depreciation - New PPA's	0	See Note 1
14	Excess (Deficient) Pension & OPEB Contribution	9,800	See Note 1
15	PV 2 Lease - Imputed Depreciation	33,236	See Note 1
16	Other Operating Leases - Imputed Depreciation	21,614	See Note 1
17	**Adjusted Funds From Operations**	806,973	Sum (Ln. 1 : Ln. 16)
	Adjusted Total Debt		
18	ADJUSTED TOTAL DEBT (2009)		
19	Long-Term Debt	3,277,051	See Note 1
20	Current Maturities of Long-Term Debt	968	See Note 1
21	Short Term Debt	355,697	See Note 1
22	AECC Short Term Debt Adjustment	(23,479)	
23	Imputed PPA Debt SRP	13,406	See Note 1
24	Imputed PPA Debt - 2005 Reliability	117,775	See Note 1
25	Imputed PPA Debt - Renewable	37,782	See Note 1
26	Imputed PPA Debt - New	-	See Note 1
27	Underfunded Pension & OPEB Debt Adjustment	269,300	See Note 1
28	Imputed Debt - PV 2 Lease	239,731	See Note 1
29	Imputed Debt - Other Operating Lease	133,539	See Note 1
30	**Adjusted Total Debt (E)**	4,421,770	Sum (Ln. 18 : Ln. 29)
31	Total Imputed Debt (2009)	811,533	Sum (Ln. 23 : Ln. 29)
32	*Target FFO/Adjusted Total Debt*	**18.25%**	Target Percent = Ln. 17 ÷ Ln. 30

Ln No.	Interim Percent Increase in Base Rates	Amount	Source
33	AECC Proposed Interim Rate Revenue	42,362	AECC Net Income Workpaper Ln. 2
34	APS ACC Jurisdiction Present Rate Revenue (2007)	2,637,447	APS Attachment DJR-1, p. 1 of 2
35	AECC Proposed Percent Increase	**1.61%**	= Ln. 33 ÷ Ln. 34

Note 1: Data Source - APS Response to ACC Staff Data Request No. 2.4 (Present Rates with No Interim DAK_WP1)

BEFORE THE ARIZONA CORPORATION COMMISSION

In the Matter of the Application of Arizona) Public Service Company for a Hearing to) Determine the Fair Value of the Utility) Property of the Company for Ratemaking) Purposes, to Fix a Just and Reasonable) Rate of Return Thereon, to Approve Rate) Schedules Designed to Develop Such Return)	**Docket No. E-01345A-08-0172**

AFFIDAVIT OF KEVIN C. HIGGINS

STATE OF UTAH)
)
COUNTY OF SALT LAKE)

Kevin C. Higgins, being first duly sworn, deposes and states that:

1. He is a Principal with Energy Strategies, L.L.C., in Salt Lake City, Utah;

2. He is the witness who sponsors the accompanying testimony entitled "Direct Testimony of Kevin C. Higgins;"

3. Said testimony was prepared by him and under his direction and supervision;

4. If inquiries were made as to the facts and schedules in said testimony he would respond as therein set forth; and

5. The aforesaid testimony and schedules are true and correct to the best of his knowledge, information and belief.

Kevin C. Higgins

Subscribed and sworn to or affirmed before me this 27th day of August, 2008, by Kevin C. Higgins.

Notary Public

My Commission Expires: 7-15-2012

Notary Public
ANGELINE WHITWORTH
Commission #575247
My Commission Expires
July 15, 2012
State of Utah

EXHIBIT
AECC-2
~~ADMITTED~~

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AZ CORP COMMISSION
DOCKET CONTROL

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN

Docket No. E-01345A-08-0172

NOTICE OF ERRATA BY FREEPORT-MCMORAN COPPER & GOLD INC. AND ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION (INTERIM RATES)

Notice is hereby given by Freeport-McMoRan Copper & Gold Inc. and Arizonans for Electric Choice and Competition ("AECC") that AECC inadvertently attached the cover page and page 1 of the Direct Testimony and Exhibits of Kevin C. Higgins (Interim Rates) of August 29, 2008 in the above referenced matter that referenced Phelps Dodge Mining Company, rather than Phelps Dodge Mining Company's Successor in Interest, Freeport-McMoRan Copper & Gold Inc. Attached are substitute pages for said cover page and page 1.

RESPECTFULLY SUBMITTED this 10th day of September 2008.

FENNEMORE CRAIG, P.C.

By C. Webb Crockett
C. Webb Crockett
Patrick J. Black
3003 N. Central Avenue, Ste. 2600
Phoenix, AZ 85012-2913

Attorneys for Freeport-McMoRan Copper and Gold Inc. and Arizonans for Electric Choice and Competition

ORIGINAL and **13 COPIES** of the foregoing
FILED this 10th day of September 2008 with:

Docket Control
ARIZONA CORPORATION COMMISSION
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By: Mary Bollington

2107153.1

BEFORE THE ARIZONA CORPORATION COMMISSION

In the Matter of the Application of Arizona) Public Service Company for a Hearing to) Determine the Fair Value of the Utility) Property of the Company for Ratemaking) Purposes, to Fix a Just and Reasonable) Rate of Return Thereon, to Approve Rate) Schedules Designed to Develop Such Return)	**Docket No. E-01345A-08-0172**

Direct Testimony of Kevin C. Higgins

on behalf of

Freeport-McMoRan Copper & Gold Inc. and

Arizonans for Electric Choice & Competition

Interim Rates

August 29, 2008

DIRECT TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Freeport-McMoRan Copper & Gold Inc. and Arizonans for Electric Choice and Competition ("AECC"). AECC is a business coalition that advocates on behalf of retail electric customers in Arizona.[1]

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward the Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist

[1] Henceforth in this testimony, Freeport-McMoRan Copper & Gold Inc. and AECC collectively will be referred to as "AECC."

EXHIBIT
RUCO-1
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

Arizona Corporation Commission
DOCKETED
AUG - 6 2008
DOCKETED BY

IN THE MATTER OF PINNACLE WEST CAPITAL CORPORATION TO PROVIDE NOTIFICATION OF ITS INTENT TO INCREASE ITS EQUITY INTEREST IN ARIZONA PUBLIC SERVICE COMPANY UNDER A.A.C. R14-2-803

DOCKET NO. E-01345A-08-0228

DECISION NO. 70454

ORDER

Open Meeting
July 29 and 30, 2008
Phoenix, Arizona

BY THE COMMISSION:

FINDINGS OF FACT

1. Arizona Public Service Company ("APS"), an Arizona class "A" public service utility that provides electric distribution services to approximately 1.1 million customers. APS is a subsidiary of Pinnacle West Capital Corporation ("PNW"). APS' current rates were approved in Decision No. 69663, dated June 28, 2007.

2. On May 2, 2008, APS filed a notice of intent to increase equity with the Arizona Corporation Commission ("Commission"), as required by Arizona Administrative Code ("A.A.C.") R14-2-803.

3. APS expects to have an approximate $400 million annual cash flow shortfall due to a difference between the funds received from operations and its capital needs. APS indicates that it is facing substantial capital needs that exceed one billion dollars in 2008 and will continue to be substantial in the foreseeable future. APS further states that the requested equity investment is

. . .

necessary for the Company to maintain investment grade credit ratings and to improve financial stability.

4. PNW indicates that it intends to infuse a total of up to $400 million into APS in the year 2008, from the proceeds of PNW common stock sales. APS does not anticipate that the $400 million equity investment will impact APS' cost of service and cost of capital in the foreseeable future.[1]

5. A.A.C. R14-2-803.A states that, "Any utility or affiliate intending to organize a public utility holding company or reorganize an existing public utility holding company will notify the Commission's Utility Division in writing at least 120 days prior thereto." Decision No. 58063, dated November 3, 1992, states that a public utility holding company increasing or decreasing its financial interest in an affiliate would be considered a reorganization and therefore would be subject to A.A.C. R14-2-803. Decision No. 58063 also exempts PNW or APS from the requirement of informing the Commission of any reorganization of an affiliate interest if the investment amount does not exceed $150 million in one calendar year. A.A.C. R14-2-803.A directs the Company to include certain information related to the reorganization in its notice of intent. The information provided by the Company in the application and supplemented by further discovery from Staff is satisfactory.

6. A.A.C. R14-2-803.B states that "The Commission will, within 60 days from the receipt of the notice of intent, determine whether to hold a hearing on the matter or approve the organization or reorganization without a hearing."

7. A.A.C. R14-2-803.C states that, ". . . the Commission may reject the proposal if it determines that it would impair the financial status of the public utility, otherwise prevent it from attracting capital at fair and reasonable terms, or impair the ability of the public utility to provide safe, reasonable and adequate service."

8. APS' capital structure as of March 31, 2008, consists of 3.0 percent short-term debt, 44.7 percent long-term debt and 52.3 percent equity. A *pro forma* capital structure reflecting the

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[1] APS currently has a rate case in progress under Docket No. E-01345A-08-0172.

proposed $400 million investment is composed of 2.8 percent short-term debt, 42.1 percent long-term debt and 55.1 percent equity.

9. For utilities with access to the capital markets, Staff typically recommends a capital structure within 40 to 60 percent equity of total capital (short-term debt plus long-term debt plus common equity) as appropriate to provide a balance of cost and financial risk.[2]

10. The appropriate capital structure for a particular utility at any specific time is dependent on various operational and general economic conditions. Providing APS authorization to issue equity capital combined with its existing authorization to issue debt would assist its efforts to maintain a capital structure that reflects its particular circumstances in recognition of the broader economic conditions.

CONCLUSIONS OF LAW

1. APS is an Arizona public service corporation within the meaning of Article XV, Section 2 of the Arizona Constitution.

2. The Commission has jurisdiction over APS and the subject matter of the application.

3. Authorization to increase equity by up to $400 million dollars would assist APS' efforts to maintain a balance of cost and financial risk in its capital structure while funding its capital expenditures.

4. There is no financial basis under A.A.C. R14-2-803.C. to reject APS' recapitalization plan.

5. No determination of the ratemaking treatment of the equity infusion is necessary or appropriate in this docket.

...

...

...

[2] Decision No. 69947, dated October 30, 2007, ordered APS to have a minimum common equity ratio of 40.0 percent immediately subsequent to the issuance of any continuing long-term debt.

ORDER

IT IS THEREFORE ORDERED that Pinnacle West Capital Corporation and Arizona Public Service Company's Notice of Intent to Increase Equity as set forth in the application and herein, is hereby approved, so long as such equity infusion is made on or before December 31, 2009.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY THE ORDER OF THE ARIZONA CORPORATION COMMISSION

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, BRIAN C. McNEIL, Executive Director of the Arizona Corporation Commission, have hereunto, set my hand and caused the official seal of this Commission to be affixed at the Capitol, in the City of Phoenix, this 6th day of August, 2008.

BRIAN C. McNEIL
EXECUTIVE DIRECTOR

DISSENT: ______________________

DISSENT: ______________________

EGJ:PMC:lhm\AH

SERVICE LIST FOR: Arizona Public Service Company
DOCKET NO. E-01345A-08-0228

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EXHIBIT
RUCO 2
ADMITTED

Summary:
Arizona Public Service Co.

Credit Rating: BBB-/Stable/A-3

Rationale

Standard & Poor's Ratings Services today affirmed the 'BBB-' corporate credit rating assigned to Pinnacle West Capital Corporation (PWCC) and its utility, Arizona Public Service. The outlook is stable. The consolidated credit ratings of PWCC primarily reflect the operations of its largest subsidiary, APS, a regulated, electric utility serving about 1.1 million customers within its service territory, which spans roughly two-thirds of Arizona and includes about half of the Phoenix MSA. We view the business profile of PWCC and APS to be 'strong'. While the company continues to benefit from a number of favorable attributes including a good service territory, a reasonably balanced power supply portfolio and a good PSA. However, APS' continues to face significant regulatory challenges.

APS provided the company with about 92% of its consolidated net income in 2007. SunCor, PWCC's real estate development company, provided about 4%, but due to the significant real estate slowdown in the southwest, it is unlikely it will be a meaningful contributor of cash flows or income over the next several years. (Prior to the real estate downturn, our forecasts have conservatively limited earnings from this subsidiary due to the cyclic nature of its cash flows.) Other subsidiary operations include Pinnacle West Trading and Marketing, which contributed about 4% of consolidated net income in 2007. This subsidiary has since last year been minimizing trading operations. Its largest contract was serving all-requirements load for UNS Electric Inc., which ended in May 2008.

We view the financial profile of PWCC and APS to be 'aggressive', which reflects: year-end debt to total capitalization of 57% (adjusted for items such as power purchases and operating leases); heavy capital spending that is expected to drive negative free operating cash flow for the foreseeable future; cash flow weakness as a function of protracted rate cases; and, while modest, the presence of unregulated activities, which can be unpredictable in their earnings contributions.

Because the preponderance of cash flows for consolidated operations stems from APS, we expect financial performance will continue to be heavily dependent on regulatory outcomes. The conclusion of APS' last general rate case in June 2007 (filed in November 2005 and revised in early 2006) provided the company with mechanisms to recover legacy deferrals and speed the recovery of fuel costs going forward. This rate relief, in place for the last half of 2007, assisted the company in maintaining credit metrics roughly in line with past performance. Funds from operations (FFO) to total debt was about 16% at year-end, with FFO interest coverage around 4x. On a trailing 12-month basis the company's performance has been slightly above these levels, due in part to the federal tax stimulus package approved by the U.S. Congress earlier this year, which is expected to increase deferred taxes (which are added back to FFO and thus increase this total).

We expect APS to be in more or less continuous rate case mode for the next few years. Given APS' capital spending program, forecasted to be about $1.1 billion annually through 2010, the utility will need to file regular general rate cases to manage recovery of its investment. The use of a historical test year in Arizona, coupled with the fact that fully litigated rate cases take between 18 to 24 months to complete, is expected to result in no meaningful improvement in financial performance through 2009 and possibly beyond, depending on the timing and the

outcome of the company's current case.

APS filed its current rate case in March 2008. ACC staff requested that the company revise its filing to reflect a test year ending Dec. 31, 2007 (as opposed to the originally filed version based on a Sept. 30, 2007, test year). The revised case has not been officially certified by the ACC, but certification is expected by July 2. Unlike the company's last rate case, in which $315 million of the $322 million of rate relief granted was for fuel and power-related costs, the majority of the current case is for nonfuel expenditures.

While the revised case increased the company's request to $278 million (about an 8.5% increase, excluding the company's request that customers be assessed about $53 million in impact fees), the re-filing means that is unlikely the ACC will reach an outcome in the case before October 2009, and because the majority of APS' sales occur in the summer months, the company's financial performance could weaken in 2009.

This month, the company requested that the ACC allow it to continue to collect a $0.004/kWh charge that it has been collecting in 2007 to recover legacy purchased power and fuel deferrals. Given that the portion of deferred costs associated with this surcharge is due to be paid by July or August, APS has asked that the ACC continue the charge, but authorize collection as an interim base rate increase, subject to refund as part of the resolution of its rate case, expected in fall 2009. (Last year, the ACC approved similar relief for Tucson Electric Power in its pending rate case settlement when it granted the southern Arizona utility the opportunity to continue to collect charges related to a competitive transition charge, or CTC, while its rate case is pending.) While retail customers would essentially see no rate increase because APS is asking to continue the surcharge as an interim increase, it is unclear what action the ACC will take. A vote could occur as early as late summer.

In 2008, we expect a procedural schedule to be established for the APS rate case, and greater clarity around the timing of an outcome will be available once this is issued. Of note is that three of the five commissioners are facing term limits and will no longer be on the ACC beginning in 2009. Commissioners are popularly elected and about a dozen candidates have announced they will run for the November election. As a result, a majority of the commissioners presiding now will not be on the commission when an APS rate case ruling is rendered. What this means for credit quality is unclear.

APS was successful earlier this year in receiving approval for a change in its line extension policies, which eliminates the free footage allowance that used to be available for customers. As a result, the portion of the company's capital expenditures associated with new line extensions will be offset with contributions in aid of construction (CIAC). This is favorable and year to date ended March 31, 2008, had added about $10 million in incremental cash flows to the company. Because it is booked under investing activities, cash flow metrics are not improved, but we recognize the significant benefit of APS receiving upfront cash from customers to meet a portion of its distribution capital investment plans. Future cash flows from customers in the form of CIAC will depend on the number of new meter sets, which are significantly off year to date due to the poor real estate market in Arizona and a slowing economy generally.

APS has a well-diversified power supply portfolio that in 2007 consisted of about 22% nuclear generation, 37% coal generation, approximately 18% owned gas generation, and the balance, about 23%, of purchases. We would expect the company's purchased power obligations to steadily climb due to the fact that APS is under a self build moratorium until 2015. APS will also need to meet relatively stringent renewable portfolio standards (RPS). It has in place a surcharge to pass through to customers the costs of RPS compliance.

Palo Verde performance has stabilized, and it has a plan in place to address NRC concerns. As of the first quarter of 2008, the combined capacity factors for all three Palo Verde units was 93%, as compared with 79% for 2007 (which reflects in part an extended planned outage to replace steam generators at unit 3) and 71% in 2006, which largely reflects unplanned outages at unit 1 related to excessive vibration that occurred when that unit exited its extended outage for refueling and replacement of steam generators. Palo Verde Unit 3 remains in the NRC's "multiple/repetitive degraded cornerstone" column of the NRC's Action matrix, which subjects all three Palo Verde units to enhanced NRC inspection regime. Preliminary work in support of this took place throughout the summer of 2007. In February, the NRC issued its inspection report, which determined the plant was operating safely but which also outlined an improvement plan for APS. In late March, APS in turn submitted to the NRC a final improvement plant addressing issues raised in the NRC inspection report. While the nuclear units appear to be on a path to improve operational performance and restore NRC confidence in the operational and safety standards at the plant, this will remain an area of concern until the NRC removes it degraded designation.

Short-term credit factors

APS and PWCC's short-term rating is 'A-3'. Liquidity is adequate. Pinnacle West has $18 million of cash and cash equivalents, and total credit facilities of nearly $1.4 billion, with approximately $943 million available as of March 31, 2008. In October 2007, APS received approval from ACC to increase its authorized short-term debt borrowing capacity by $500 million, and long-term debt borrowing capacity by $1 billion. This will help address the needs of its growing customer base, and the increasing requirement for natural gas and purchased power.

Pinnacle West had close to $185 million available under its $300 million unsecured revolving credit facility that expires in December 2010. APS had $682 million available under its two unsecured revolving credit facilities, $400 million of which expires in December 2010, and $500 million in September 2011. SunCor has two credit facilities expiring in October and December 2008 that total $170 million and approximately $76 million, respectively, available as of September 2007.

Discretionary cash flow is expected to be negative for 2008 due to APS' capital expenditure plans. Excluding the remarketing of APS' pollution control debt, neither PWCC nor APS has any significant debt obligations maturing until 2011.

Outlook

The stable outlook reflects our expectation that consolidated cash flow volatility has been tamped down by the ACC's approval of a stronger PSA that speeds the recovery of fuel costs, but consolidated financial performance will continue to be challenged by regulatory lag at APS, which could be moderated by APS' pending interim rate request. The stable outlook is premised on no meaningful adverse changes in the company's business risks and continued financial performance that is not significantly weaker than 2007 results. Equity issuances will be expected to balance the capital structure of the company as APS continues to invest heavily in infrastructure. Ratings could be lowered to speculative grade if the company is not able to overcome the challenge of ensuring timely recovery of its prudently incurred costs through rate increases approved by the ACC. Given these challenges, and that presented by NRC scrutiny of Palo Verde, we see little potential for positive movement in the ratings or outlook.

EXHIBIT

RUCO-3

ADMITTED

STANDARD &POOR'S

RATINGSDIRECT®

November 30, 2007

U.S. Utilities Ratings Analysis Now Portrayed In The S&P Corporate Ratings Matrix

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U.S. Utilities Ratings Analysis Now Portrayed In The S&P Corporate Ratings Matrix

The electric, gas, and water utility ratings ranking lists published today by Standard & Poor's U.S. Utilities & Infrastructure Ratings practice are categorized under the business risk/financial risk matrix used by the Corporate Ratings group. This is designed to present our rating conclusions in a clear and standardized manner across all corporate sectors. Incorporating utility ratings into a shared framework to communicate the fundamental credit analysis of a company furthers the goals of transparency and comparability in the ratings process. Table 1 shows the matrix.

Table 1

Business Risk/Financial Risk

	Financial Risk Profile				
Business Risk Profile	**Minimal**	**Modest**	**Intermediate**	**Aggressive**	**Highly leveraged**
Excellent	AAA	AA	A	BBB	BB
Strong	AA	A	A-	BBB-	BB-
Satisfactory	A	BBB+	BBB	BB+	B+
Weak	BBB	BBB-	BB+	BB-	B
Vulnerable	BB	B+	B+	B	B-

The utilities rating methodology remains unchanged, and the use of the corporate risk matrix has not resulted in any changes to ratings or outlooks. The same five factors that we analyzed to produce a business risk score in the familiar 10-point scale are used in determining whether a utility possesses an "Excellent," "Strong," "Satisfactory," "Weak," or "Vulnerable" business risk profile:

- Regulation,
- Markets,
- Operations,
- Competitiveness, and
- Management.

Regulated utilities and holding companies that are utility-focused virtually always fall in the upper range ("Excellent" or "Strong") of business risk profiles. The defining characteristics of most utilities--a legally defined service territory generally free of significant competition, the provision of an essential or near-essential service, and the presence of regulators that have an abiding interest in supporting a healthy utility financial profile--underpin the business risk profiles of the electric, gas, and water utilities.

As the matrix concisely illustrates, the business risk profile loosely determines the level of financial risk appropriate for any given rating. Financial risk is analyzed both qualitatively and quantitatively, mainly with financial ratios and other metrics that are calculated after various analytical adjustments are performed on financial statements prepared under GAAP. Financial risk is assessed for utilities using, in part, the indicative ratio ranges in table 2.

Table 2

Financial Risk Indicative Ratios - U.S. Utilities

(Fully adjusted, historically demonstrated, and expected to consistently continue)

	Cash flow		Debt leverage
	(FFO/debt) (%)	(FFO/interest) (x)	(Total debt/capital) (%)
Modest	40 - 60	4.0 - 6.0	25 - 40
Intermediate	25 - 45	3.0 - 4.5	35 - 50
Aggressive	10 - 30	2.0 - 3.5	45 - 60
Highly leveraged	Below 15	2.5 or less	Over 50

The indicative ranges for utilities differ somewhat from the guidelines used for their unregulated counterparts because of several factors that distinguish the financial policy and profile of regulated entities. Utilities tend to finance with long-maturity capital and fixed rates. Financial performance is typically more uniform over time, avoiding the volatility of unregulated industrial entities. Also, utilities fare comparatively well in many of the less-quantitative aspects of financial risk. Financial flexibility is generally quite robust, given good access to capital, ample short-term liquidity, and the like. Utilities that exhibit such favorable credit characteristics will often see ratings based on the more accommodative end of the indicative ratio ranges, especially when the company's business risk profile is solidly within its category. Conversely, a utility that follows an atypical financial policy or manages its balance sheet less conservatively, or falls along the lower end of its business risk designation, would have to demonstrate an ability to achieve financial metrics along the more stringent end of the ratio ranges to reach a given rating.

Note that even after we assign a company a business risk and financial risk, the committee does not arrive by rote at a rating based on the matrix. The matrix is a guide--it is not intended to convey precision in the ratings process or reduce the decision to plotting intersections on a graph. Many small positives and negatives that affect credit quality can lead a committee to a different conclusion than what is indicated in the matrix. Most outcomes will fall within one notch on either side of the indicated rating. Larger exceptions for utilities would typically involve the influence of related unregulated entities or extraordinary disruptions in the regulatory environment.

We will use the matrix, the ranking list, and individual company reports to communicate the relative position of a company within its business risk peer group and the other factors that produce the ratings.

The McGraw-Hill Companies

BEFORE THE ARIZONA CORPORATION COMMISSION

EXHIBIT
RUCO-4
ADMITTED

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CHAIRMAN
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GARY PIERCE
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	Docket No. E-01345A-08-0172

NOTICE OF FILING

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Direct Testimony of Stephen Ahearn in the above-referenced matter.

RESPECTFULLY SUBMITTED this 2nd day of September 2008

Daniel W. Pozefsky
Chief Counsel

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By Ernestine Gamble
Ernestine Gamble
Secretary to Daniel Pozefsky

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-08-0172

DIRECT TESTIMONY

OF

STEPHEN AHEARN

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

SEPTEMBER 2, 2008

INTRODUCTION

Q. Please state your name and business address for the record.

A. My name is Stephen Ahearn. My business address is 1110 West Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. I have been employed by the state of Arizona as the Director of the Residential Utility Consumer Office ("RUCO") since January 2003. From 1998 through 1999, I was employed at the Arizona Corporation Commission in the capacity of Executive Consultant. From 1990 to 1998, I was actively involved with utility regulation at the Commission and utility policy-making at the Legislature in my role as the Manager of Planning and Policy at the Department of Commerce Energy Office. Additionally, I have had training in utility ratemaking and telecommunications policy conducted by NARUC and New Mexico State University, respectively. Finally, I have an MBA in Finance from UCLA.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present recommendations resulting from my review of the Arizona Public Service Company's ("Company" or "APS") request for an emergency interim rate increase.

INTERIM RATE REQUEST - BACKGROUND

Q. Please discuss the Company's emergency interim rate request.

A. The Company claims it needs $115 million in interim relief in order "to help staunch a growing financial threat to itself and its customers."

Q. Wasn't APS granted several rate increases over the last few years?

A. Yes. Most recently, APS was granted a $322 million rate increase in Decision No. 69663, dated June 28, 2007. The increase was awarded pursuant to a traditional rate case where there was a finding of fair value. Approximately one year prior to that increase, APS requested an emergency rate increase of $299 million. In Decision No. 68685, dated May 5, 2006, the Commission found that APS' situation did not constitute an emergency under the Arizona Constitution. However, the Commission did find that rate relief was warranted utilizing APS' Power Supply Adjustor (PSA) mechanism, thus avoiding the fair value requirement. In April of 2005, in Decision 67744, the Commission granted APS a $75.5 million increase via a settlement agreement of an underlying traditional finding-of-fair-value rate case filing. APS currently has a rate case pending where it has requested a $488 million rate increase.

..

..

Q. With the numerous recent rate increases and with an application pending, why is APS again deviating from the traditional rate case process in order to request these interim rates?

A. APS answers with a variant of the same theme it employed in its "emergency" filing in 2006. The main arguments include:

- The impending threat of a credit rating downgrade due to poor credit metrics, particularly the oft-cited FFO/Debt ratio
- The high cost of infrastructure to serve load growth while maintaining reliability
- That revenue generated from growth is insufficient to pay for the growth
- The consequences of regulatory lag

All of these arguments have served APS well in past rate requests, as the Commission has granted significant rate relief and favorable adjuster mechanism treatment on each occasion. These arguments, however, were used unsuccessfully by the Company when it attempted to establish that an emergency existed two years ago in their filing for interim rates at that time. In the instant case, the Company is again in effect claiming an emergency because of the high cost of infrastructure development, regulatory lag and the threat of a credit rating downgrade.

A pattern is developing in the Company's filings: for the second rate filing in a row, the Company has followed up its traditional application with a request to speed up collection using a variant of the "emergency" or interim application.

Further, in the instant matter, rather than file a case that is predicated on a year's worth of expense and revenue data from a year's experience with new rates, the Company is filing a case that requires the use of projections.

INTERIM RATES - CRITERIA

Q. What criteria are used in Arizona regarding interim rates?

A. The Arizona Office of the Attorney General issued Opinion No. 71-17 on May 25, 1971 regarding interim rates. In that opinion, the attorney general concluded that "the Commission may approve interim rates only upon a finding that an emergency exists"[1]

Q. What specifically does the opinion state regarding the need to qualify as an emergency?

A. At page 11 and 12, the opinion states:

> [E]mergency rates would not be justified, except as a condition is shown which, if not relieved from, will imperil the property of the company and its service to the public, such as might subject the company at once to proceedings in bankruptcy or receivership; that mere inability to make profits or pay dividends would not create an emergency. (quoting Omaha & Council Bluffs Street Railway Co. v. Nebraska City Railway Commission, 173 N.W. 690 Neb. 1919).

And at page 13:

> [I]n general, courts and regulatory bodies utilize interim rates as an emergency measure when sudden change brings hardship to a

[1] There are other situations, which are not applicable here, where interim rates may be appropriate. For example, when final rates are not put into effect within the statutory timelines, the Commission may establish interim rates subject to refund pursuant to AAC R14-2-103(ii)(h).

> company, when the company is insolvent, or when the condition of the company is such that its ability to maintain service pending a formal rate determination is in serious doubt.

INTERIM RATES – THE VALIDITY OF THE COMPANY'S ARGUMENTS

Q. The Company argues that interim rates are necessary to mitigate "timing differences" that arise as a result of the lag between the plant construction period and the time when the plant enters service and is included in rates. Please comment.

A. Such "timing differences" do not constitute an emergency, therefore the Company's arguments do not justify interim rates because there have been no sudden changes, the Company is not insolvent, and there is no question that the Company can continue to maintain service.

Q. Please explain.

A. The "timing differences" referred to by the Company are a normal result of regulation. All regulated utilities experience "timing differences" as part of the regulatory process. Accordingly, "timing differences" alone do not constitute an emergency for which interim rates are warranted. Furthermore, such "timing differences" historically work both for and against a utility and therefore, tend to offset each other over time.

Q. When the Commission denied APS' emergency interim rate request in May 2006 what criteria did they rely on?

A. The Commission relied primarily on the Arizona Constitution Article 15, which requires a finding of fair value in order to increase rates, and Attorney General Opinion 71-17, which opines that the Commission may approve interim rates only upon a finding that an emergency exists. Decision No. 68685 specifically states that the criteria necessary for the granting of emergency interim rates, as set forth in Opinion 71-17 was not met by APS in its request.

Q. Are the circumstances any different in APS' current emergency interim rate request than they were back in 2006 when the Commission denied the Company's request?

A. No. The Company is claiming the threat of credit downgrade, large capital expense budget, regulatory lag and high fuel and purchased power costs. These are the same arguments APS made in its last plea of an emergency. The Commission correctly determined in that case that the circumstances did not meet the criteria for an emergency. Since nothing has changed in the current case the Commission should reach the same conclusion, and deny APS' request.

Q. Are there issues in this case that go beyond the emergency rate request?

A. Yes. This APS request is yet another example of how Arizona utilities are attempting to redefine the regulatory paradigm in Arizona, which has worked fairly and rationally for decades. Utilities, through requests for automatic adjustors, interim/emergency rates, single issue ratemaking, decoupling mechanisms, and "ACRM-like" mechanisms would like to create a new regulatory system that shifts the risk from their shareholders to their ratepayers. Consideration of these types of schemes is a very slippery slope that could easily lead to a situation where monopoly enterprises could operate in the absence of any effective or meaningful regulation.

Moreover, requests for these types of schemes have become the norm and not the exception. This case is a perfect example – two years ago APS requested interim rates. While APS was not successful on its argument that an "emergency" existed at that time APS was still afforded a rate increase through its PSA mechanism. Extraordinary relief, if ever, should only be allowed in extraordinary situations. The Commission should not allow non-traditional ratemaking practices to become the norm.

Q. Does this conclude your direct testimony?

A. Yes.

EXHIBIT
S-1

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN

DOCKET NO. E-01345A-08-0172

DIRECT

TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

AUGUST 29, 2008

TABLE OF CONTENTS

Page

ATTACHMENTS:

EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-08-0172

Staff recommends that APS' request for an interim rate increase be denied.

My testimony addresses the following issues:

A. The Interim Rate Relief Requested by APS
B. Criteria for Interim Rate Relief
C. Ordinary Regulatory Lag Does Not Justify APS' Requested Interim Rate Relief
D. Alleged Emergency Circumstances
E. Whether APS Requires an Interim Rate Increase During the Processing of its General Rate Case
F. An Alternative Basis for Determining an Amount of Interim Rate Increase for APS Should the Commission be Inclined to Grant an Increase
G. Rate Design

A. The Interim Rate Relief Requested by APS

APS is seeking an interim rate increase of approximately $115 million, or approximately 4 mills per kWh, to be effective with the first billing cycle of November, 2008. If granted, any interim rates would be subject to refund with interest, pending the Commission's final decision in APS' general rate case.

APS' application at various places claims that, from the end of the September 30, 2005, test year used to set the Company's present rates in Decision No. 69663 (6/28/2007) to May 31, 2008, the Company has invested in over $1.7 billion for new facilities that are not reflected in current rates. APS' response to Staff Interim 1.13 states that the purpose of the surcharge would be to ameliorate the detrimental impact of the Company's rising non-fuel costs until the Commission has the opportunity to enter an order on the Company's permanent rate request in the underlying general rate case.

APS points to a number of factors as supporting its request for interim rates, including: its inability in recent years to earn its authorized return on equity (ROE); its recent actual and projected net cash flow, which requires access to outside financing; the poor stock price performance of its parent company, Pinnacle West Capital Corporation ("PNW" or "PWCC") compared with other investor-owned utilities; its bond ratings, which APS states are "currently among the lowest they can possibly be without being regarded as "junk"; and its Funds From Operations to Debt ("FFO/Debt") ratio, which APS asserts is the key financial metric examined by the credit rating agencies, and which measures the sufficiency of a company's cash flow to service both debt interest and debt principal over time. For APS' present "business profile" category, APS states that Standard & Poor's expects APS to maintain an FFO/Debt ratio of 18% to 28%. If no rate increase is granted in the current general rate case, APS projects its FFO/Debt

ratio will decline to 17.6% at the end of 2009 and to 16.6% at the end of 2010 under present rates, even with an equity infusion of $400 million.
APS claims that the Company's financial condition will continue to deteriorate during the period of regulatory lag associated with the processing of a general rate case, and the Company will once again be on the brink of a downgrade to junk credit status in 2009 before the Commission will likely have ruled on its general rate application.

B. Criteria for Interim Rate Relief

Interim rate increases can be appropriate if the Commission is unable to process a utility's base rate increase request in a timely manner, if the utility is experiencing an emergency, or if other special circumstances are present.

An emergency could generally include circumstances that threaten or interfere with a Company's ability to provide safe and reliable service, such as insolvency or a sudden, unanticipated occurrence. Some conditions that could constitute a financial emergency include an inability to raise capital at reasonable terms, inability to meet required coverage ratios specified in bond indentures, a cash flow crisis, or an inability to pay current expenses.

In Docket No. E-01345A-06-0009, Staff concluded that the question of what qualifies as an emergency is largely an issue of fact for the Commission to decide. Staff also concluded that the facts in that case did not warrant emergency interim rate relief. The following quote from pages 3-4 of Staff's brief summarizes the evaluation by Staff in that proceeding:

> *Most emergency rate cases before the Commission in the past ten to fifteen years involved small water systems facing a crisis of being unable to provide adequate and reliable service without an immediate increase in rates. Many of the cases involved significant operational and maintenance deficiencies. See Decision Nos. 57841 (Mountain View Water Company) and 67990 (Sabrosa Water Company). Others involved water quality and regulatory compliance issues from other state agencies. See Decision Nos. 61833 (Far West Water Company) and 62651 (Thim Utility Company, E&T Division). The Commission, however, has also denied or partially denied applications for emergency rate relief. See Decision Nos. 57668 (E & R Water Company et. al.), 59250 (Mountain View Water Company) and 61930 (Vail Water Company). Appendix A lists several cases where the Commission has heard emergency interim rate relief cases, some of which have been cited above. In the majority of those cases where emergency interim rate relief was approved, the crisis defined by the company had already occurred or was occurring.*
>
> ...
>
> *The evidence in this case is that there is no threat of insolvency or a liquidity crisis if APS' request is not granted. (Tr. at 392). APS contends that the possible downgrade of its credit rating to junk status is the emergency at hand, and that this meets the criteria of an emergency set forth in the Arizona Attorney General's*

Opinion 71-17...Staff does not agree with APS that a downgrade is imminent based on what the credit rating agencies have stated in their written reports. In other words, a sudden change to APS' credit rating appears unlikely...And no evidence was presented that APS will not be able to continue providing adequate and reliable service before the permanent rate case is resolved. The public interest does not necessitate the granting of emergency interim rate relief requested by APS.

The current APS request for an interim rate increase bears some similarities with Docket No. E-01345A-06-0009. Again, APS has focused concern on the potential for a credit ratings downgrade. One key difference between that 2006 APS emergency rate increase request and APS' current request for interim rates is that in Docket No. E-01345A-06-0009 a primary focus was on the operation of APS' Power Supply Adjustor ("PSA") mechanism and the potential under that mechanism, as it existed at that time, for growing deferrals of fuel cost. In APS' current application for interim rates, the operation of the PSA is not a significant concern, as I explain in a subsequent section of my testimony. APS' has instead focused its present request for Interim Rates on the alleged negative impact of regulatory lag as it applies to APS' recovery of plant investment.

C. Ordinary Regulatory Lag Does Not Justify APS' Requested Interim Rate Relief

A procedural schedule has been established for processing APS' general rate case. While unforeseen events may occur, at this time Staff expects that it will be processed according to the established procedural schedule.

At page 2, lines 16-17, of its application APS has claimed that it has expended $1.7 billion for new facilities that are not reflected in current rates. APS' response to Staff Interim 2.96(f) provided a breakout of the $1.7 billion by type of plant and period. The $1.7 billion claimed by APS includes $297 million of capital expenditures beyond December 31, 2007, the end of the test year in the current rate case. Moreover, the APS capital expenditures do not directly translate into a rate base increase because during the same time frame Accumulated Depreciation, which is an offset to gross plant, is also growing significantly. Consequently, the $1.7 billion is not an appropriate basis for determining the increase in APS' net plant in service between the end of its last test year and the end of the test year in the pending general rate case. The $1.7 billion, in essence, does not represent the net amount of jurisdictional rate base increase that has been financed by investors. In fact, it significantly overstates that amount.

Based on a preliminary review of APS' current general rate case application, a comparison between the rate base specified in Decision No. 69663 from APS' last rate case, which had used a test year ending September 30, 2005, through the end of the test year in the current rate case, December 31, 2007 (without pro forma adjustments), APS' jurisdictional rate base has grown by approximately $538 million.

Although these factors should be examined in the general rate case, they do not necessitate interim rate relief within the circumstances of this case. Regulatory lag is an ordinary and anticipated feature of regulation. One of the useful functions of regulatory lag is to place financial responsibility upon the utility for fluctuations in costs between rate cases. The regulatory lag feature of Rate Base/Rate of Return regulation is essential to effective and efficient operation of such a regulatory régime. Because of the lag between placing new plant into service and obtaining rate recognition of such plant, the utility may bear the cost of new plant additions temporarily. This can encourage management to emphasize cost control to a higher degree than might be expected if cost responsibility for plant additions during the periods between rate cases were shifted away from the utility and onto ratepayers. In evaluating plant additions, the Company should conduct a cost-benefit analysis to determine if there is a business case for implementing the plant additions in the time frame budgeted by the Company. If the case is compelling and the project is cost-justified, no additional special ratemaking treatment is needed. If the project is not cost-justified or the benefits are too speculative to warrant the commitment of funds, it may be prudent to delay or avoid the related capital expenditures. These incentives that are currently in place would be lessened if ordinary regulatory lag began to be utilized by Arizona utilities as a justification for interim rate increases. Absent some emergency or other exceptional circumstance, ordinary regulatory lag by itself does not warrant the extraordinary relief of an interim rate increase.

D. Alleged Emergency Circumstances

Pages 18-19 of APS witness Brandt's affidavit claims that: "... notwithstanding proactive efforts from the Company and Pinnacle West, APS' credit metrics will fall into junk credit range during the course of the Company's rate proceedings, before the Commission is likely to grant the much-needed rate relief. I firmly believe that the Company will more than likely be downgraded to junk during the pendency of the general rate case proceedings without interim relief." In response to Staff Interim 2.97, APS stated that: "While the Company hopes that it is able to continue to provide safe and reliable electric service to customers in 2008 and 2009 and intends to do so, the Company's interim base rate request is intended to support its overall financial health so that its ability to offer reliable electric service will not be jeopardized in the future."

APS is not currently experiencing a financial emergency. Staff's analysis reveals that APS has been and continues to be able to obtain financing. As explained in my and Staff witness Parcell's testimonies, APS is not currently experiencing a financial crisis and is not facing a cash flow emergency.

APS' response to data request Staff Interim 2.50 (among others) shows that APS' current long term debt ratings are:

S&P: BBB-
Moody's: Baa2
Fitch: BBB

A downgrade of APS' credit rating does not appear imminent or probable during the processing of APS' general rate case. According to APS' response to data request Staff Interim 2.27(b) no credit rating agencies have announced that APS' debt would be downgraded if APS' request for interim rates were to be denied. All three credit rating agencies list APS' outlook as "stable."

Staff concludes that APS has not identified any sudden or unanticipated circumstance affecting its ability to offer reliable electric service that would justify an interim rate increase.

E. Whether APS Requires an Interim Rate Increase During the Processing of its General Rate Case

Attachment RCS-3, page 20 lists the ranges of financial risk indicative ratios for a corporation or a U.S. utility, such as APS, with a business risk profile of "strong" and a financial risk profile of "aggressive." A similar listing of ranges indicated by S&P for U.S. Utilities appears in Attachment RCS-2, page 63. The ranges listed by S&P for the applicable "financial risk indicative ratios" are:

S&P 2008 Corporate and U.S. Utilities Ratings Criteria		**U.S.**
Financial Risk Indicative Ratios*	**Corporate[1]**	**Utilities[2]**
BBB- Range		
Cash flow (funds from operations/Debt) %	15-30	10-30
Cash flow (FFO/interest) (times)		2.0-3.5
Debt leverage (Total debt/Capital) %	45-55	45-60
Debt/EBITDA (times)	3.0-4.5	
*Fully adjusted, historically demonstrated, and expected to continue consistently Business risk profile "solid"; financial risk profile "aggressive"		
[1] Standard & Poor's 2008 Corporate Ratings Criteria		
[2] Source: Standard & Poor's Ratings Direct, 11/31/2007; U.S. Utilities Ratings Analysis Now Portrayed in the S&P Corporate Ratings Matrix		

Staff data requests 2.59 and 2.60 asked APS to run various scenarios of interim and permanent rate increases, and to calculate the impact on its FFO/Debt ratio, among other things. The following table summarizes those results from APS' second supplemental response to Staff Interim 2.59:

APS Calculated FFO/Adjusted Total Debt Under Various Scenarios

		Estimated FFO/Adjusted Total Debt		
Case #	Description[a]	2008	2009	2010
1	100% of $115M Interim Nov'08, 100% of Non-Fuel Base Rate Increase 10/1/09 (5%)	23.3%	20.7%	21.3%
2	100% of $115M Interim Nov'08, 50% of Non-Fuel Base Rate Increase 10/1/09 (5%)	23.3%	20.2%	18.9%
3	50% of $115M Interim Nov'08, 100% of Non-Fuel Base Rate Increase 10/1/09 (5%)	23.2%	19.9%	21.0%
4	50% of $115M Interim Nov'08, 50% of Non-Fuel Base Rate Increase 10/1/09 (5%)	23.2%	19.4%	18.7%
5	No $115M Interim Nov'08, 100% of Non-Fuel Base Rate Increase 10/1/09 (5%)	23.0%	19.1%	20.8%
6	No $115M Interim Nov'08, 50% of Non-Fuel Base Rate Increase 10/1/09 (5%)	23.0%	18.7%	18.5%
7	50% of $115M Interim Nov'08, 75% of Non-Fuel Base Rate Increase 10/1/09 (7.5%)	23.2%	19.7%	19.8%
8	50% of $115M Interim Nov'08, 25% of Non-Fuel Base Rate Increase 10/1/09 (2.5%)	23.2%	19.2%	17.6%
9	No $115M Interim Nov'08, 75% of Non-Fuel Base Rate Increase 10/1/09 (7.5%)	23.0%	18.9%	19.7%
10	No $115M Interim Nov'08, 25% of Non-Fuel Base Rate Increase 10/1/09 (2.5%)	23.0%	18.4%	17.4%

Notes

[a] All case scenarios shown in this table also reflect an assumed fuel-related increase effective 10/1/09 (7%)

As shown in the above table, with no interim increase and assuming 50% of its base rate increase is granted with rates effective October 1, 2009, APS' FFO/Debt ratio is expected to be 23.0% in 2008, 18.7% in 2009, and 18.5% in 2010, all of which are within Standard & Poor's BBB- "investment grade" range for a corporation with APS' business and financial risk profile of 15% to 30% as stated in the S&P 2008 Corporate Ratings Criteria and are within the 10% to 30% range specified in S&P's U.S. Utilities Ratings Analysis. These are also above the range of 18.0% to 28.0% that APS witness Brandt states that "S&P expects APS to maintain." This suggests that APS does not need any interim rate increase in order to keep its FFO/Debt ratio in a range appropriate for APS' current bond ratings through 2010. In other words, APS does not need any interim rate increase in 2008 or 2009 in order to keep its FFO/Debt ratio within an "investment grade" range. The level of base rate relief in the general rate case will affect APS' FFO/Debt ratio in 2009 and 2010.

The interim rate relief that APS has requested would not necessarily prevent future downgrades of the Company's debt ratings. Factors outside of the Commission's control, such as a sustained unscheduled outage at Palo Verde, could result in an adverse impact on APS's credit ratings, regardless of whether an interim increase is granted.

If APS' debt were to be downgraded to below investment grade status, such an outcome would not be good for either APS or its ratepayers. However, APS has not demonstrated that its requested interim rate increase is necessary in order to do that.

In 2007, the Commission approved an increase to APS' borrowing (Decision No. 69947) and, on August 6, 2008 approved an equity infusion of up to $400 million from APS' parent, Pinnacle

West (Decision No. 70454). In Docket No. E-01345A-08-0228, PNW indicated that it intended to infuse up to $400 million into APS in the year 2008. In that docket, APS indicated that it is facing substantial capital needs in 2008 and the foreseeable future and the requested equity investment is necessary to allow APS to maintain current investment grade credit and to improve financial stability. Consequently, by authorizing that equity infusion in Decision No. 70454, the Commission has already provided APS with a means whereby APS and its parent, PNW, can help maintain their current investment grade credit and improve financial stability during the pendency of APS' current general rate case. If APS is truly concerned about its financial ratios, obtaining the equity infusion from PNW sooner, rather than waiting to year-end 2009, would be one step that APS and its parent, PNW, could take to help address their own concerns about APS' financial ratios during the pendency of APS' current general rate case.

Staff's evaluation of APS' financial condition concludes that APS' debt is investment grade. Investment rating agencies such as Standard & Poor's, Moody's and Fitch rank APS' debt as investment grade, and those agencies have listed their outlook for APS and PNW as "stable." Moreover, other key financial metrics for APS appear solid for its business profile. APS' FFO/Debt ratio is currently well within the 15% to 30% range specified by Standard & Poor's for a BBB- rating for a corporation with a "strong" business risk profile and an "aggressive" financial risk profile and within the 10% to 30% range for a U.S. utility with that business and financial risk profile. APS has projected its FFO/Debt ratio to be 23.0% in 2008 even without any interim rate increase. Moreover, as Staff witness Parcell explains, the credit rating agencies look at other financial ratios and information; thus, a temporary dip in one financial metric, APS' FFO/Debt ratio, in 2009 below 18% will not necessarily result in a downgrade. APS and its parent, PNW, can help themselves maintain an FFO/Debt ratio in the "investment grade" range by making the Commission-authorized $400 million equity infusion into APS sooner, rather than later.

Based on the information provided by APS and the analysis performed by Staff, APS' financial condition appears to be sound enough to not require an interim rate increase during the processing of its general rate case. After the Commission's actions in Decision No. 70454, and based on Staff's analysis and the current time-table for establishing new base rates for APS in the current APS general rate case, APS does not require a $115 million interim rate increase at this time. The basis for the amount of interim rate increase requested by APS is tied to the approximately 4 mils per kWh of a PSA surcharge that expired in July 2008. Since that surcharge has expired, and has been removed from customer rates as originally intended upon full recovery of the surcharged costs, there is no need to now tie the amount of an interim rate increase to an expired fuel surcharge. Moreover, the amount of interim increase need not, and should not be, tied to the amount of the PSA surcharge that expired in July 2008.

F. An Alternative Basis for Determining an Amount of Interim Rate Increase for APS Should the Commission be Inclined to Grant an Increase

Staff is not recommending an interim rate increase during the pendency of APS' general rate case. If the Commission were inclined to grant APS some amount of interim rate relief, I am advised that it may be necessary for APS to post a bond. In response to Staff Interim 2.74, APS estimates that the cost of a surety bond or a letter of credit would be approximately 1% of the face value. Thus, granting an interim rate increase may result in an additional cost to APS and its ratepayers related to the cost of the surety bond or letter of credit.

Staff is presenting the Commission with an alternative basis for determining an amount of interim rate increase, should the Commission be inclined to grant one. Staff's alternative is based on the growth in APS' jurisdictional rate base from Decision No. 69663 in APS's last rate case through the end of the test year in the current rate case December 31, 2007 (without pro forma adjustments). Based on the growth in jurisdictional rate base during that period, Staff's alternative would provide an interim rate increase of approximately $65 million. For comparative purposes, the $65 million would represent approximately 56.5% of the $115 million interim rate increase requested by APS.

Any interim rate increase granted to APS should be contingent upon the completion of the $400 million equity infusion approved by the Commission in Decision No. 70454.

G. Rate Design

APS witness Rumolo's affidavit presents three options for rate design for an interim rate increase:

1) Applying the same per kWh charge to all affected customers;
2) Applying a fixed percentage of base rates uniformly across all rate schedules; and
3) A two-step process, which would first assign the revenue requirement to customer classes (i.e., residential, general service, industrial, etc.) on an energy basis. For customers who are billed on a demand basis, the revenue increase would be converted to a per kW demand charge.

The rate design for an interim increase should be simple and straight-forward to implement and should also facilitate being able to track and verify the revenue produced by the Interim Rate increase in case there is a need to make refunds. If any interim rate increase is granted, Staff recommends that the Interim Base Rate Surcharge use the same per-kWh charge for all affected customers.

INTRODUCTION

Q. Please state your name, position and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Please describe Larkin & Associates.

A. Larkin & Associates is a Certified Public Accounting and Regulatory Consulting firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates has extensive experience in the utility regulatory field as expert witnesses in over 400 regulatory proceedings including numerous telephone, water and sewer, gas, and electric matters.

Q. Mr. Smith, please summarize your educational background.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the C.P.A. examination in my first sitting in 1979, received my CPA license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I am a licensed Certified Public Accountant and attorney in the State of Michigan. I am also a Certified Financial Planner™ professional and a Certified Rate of Return Analyst ("CRRA"). Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the Michigan Bar Association and the Society of Utility and Regulatory Financial Analysts ("SURFA"). I have also been a member of the American Bar Association ("ABA"), and the ABA sections on Public Utility Law and Taxation.

Q. Please summarize your professional experience.

A. Subsequent to graduation from the University of Michigan, and after a short period of installing a computerized accounting system for a Southfield, Michigan realty management firm, I accepted a position as an auditor with the predecessor CPA firm to Larkin & Associates in July 1979. Before becoming involved in utility regulation where the majority of my time for the past 26 years has been spent, I performed audit, accounting, and tax work for a wide variety of businesses that were clients of the firm.

During my service in the regulatory section of our firm, I have been involved in rate cases and other regulatory matters concerning numerous electric, gas, telephone, water, and sewer utility companies. My present work consists primarily of analyzing rate case and regulatory filings of public utility companies before various regulatory commissions, and, where appropriate, preparing testimony and schedules relating to the issues for presentation before these regulatory agencies.

I have performed work in the field of utility regulation on behalf of industry, state attorney generals, consumer groups, municipalities, and public service commission staffs concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Washington, Washington D.C., Wisconsin, and

Canada as well as the Federal Energy Regulatory Commission and various state and federal courts of law.

Q. Have you prepared an attachment summarizing your educational background and regulatory experience?

A. Yes. Attachment RCS-1 provides details concerning my experience and qualifications.

Q. Have you previously submitted testimony concerning interim or emergency rate increases?

A. Yes. I testified in Docket No. E-01345A-06-0009, a request in 2006 by APS for an Emergency Interim Rate Increase.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff").

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes. I have testified before the Commission previously on a number of occasions.

Q. What is the purpose of the testimony you are presenting?

A. The purpose of my testimony is to address the application for an interim rate increase filed by Arizona Public Service Company ("APS" or "Company").

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes. Attachments RCS-2 contains copies of selected APS responses to discovery and other documents that are referenced in my testimony.

Q. Please briefly describe the information you reviewed in preparation for your testimony.

A. The information I reviewed included APS's application and testimony, APS's responses to data requests of Staff and other parties, information provided to me by Staff, and other publicly available information.

Q. What is Staff's recommendation on this matter?

A. Staff recommends that APS' request for an interim rate increase be denied.

DISCUSSION OF ISSUES

Q. What issues are addressed in your testimony?

A. My testimony addresses the following issues:

A. The Interim Rate Relief Requested by APS
B. Criteria for Interim Rate Relief
C. Ordinary Regulatory Lag Does Not Justify APS' Requested Interim Rate Relief
D. Alleged Emergency Circumstances
E. Whether APS Requires an Interim Rate Increase During the Processing of its General Rate Case
F. An Alternative Basis for Determining an Amount of Interim Rate Increase for APS Should the Commission be Inclined to Grant an Increase
G. Rate Design

A. The Interim Rate Relief Requested by APS

Q. Please provide some background for the request that APS has made in the current proceeding.

A. APS is an Arizona utility providing electricity to more than 1 million customers in 11 of Arizona's 15 counties. With its headquarters in Phoenix, APS is the largest subsidiary of Pinnacle West Capital Corporation ("PWCC" or "PNW"[1]).

APS' current base rates became effective July 1, 2007 pursuant to Decision No. 69663, dated June 29, 2007. That case, Docket No. E-01345A-05-0816 et al, used a test year ending September 30, 2005.

On March 24, 2008, APS filed with the Commission an application for a base rate increase. On June 2, 2008, APS filed an amended application for a net increase in rates of $278.2 million, using a test year ending December 31, 2007. The $278.2 million is composed of a $264.3 million non-fuel related base rate increase plus a $13.9 million effective net increase in fuel-related base rates. APS' requested increase in non-fuel base rates includes a $79.3 million allowance for attrition that purports to measure the impact of regulatory lag through 2010, the first full calendar year that new rates would be in effect. APS proposes to collect up to $53 million of that attrition amount through a new "hook up" fee that would be applicable to APS customers at a new service location.

On July 6, 2008, in the instant proceeding, Docket No. E-01345A-08-0172, APS filed a motion for approval of an interim rate. APS is seeking an interim rate increase of approximately $115 million, or approximately 4 mills per kWh, to be effective with the first billing cycle of November 2008, and subject to refund. APS derived the amount of

[1] PNW is the stock symbol for Pinnacle West Capital and rating agency and investment reports sometimes therefore use "PNW." In this testimony, both abbreviations, PWCC and PNW, are used interchangeably.

interim increase with reference to a Power Supply Adjustor surcharge of $0.003987 per kWh that had been approved in Decision No. 69663 to collect a $46 million balance of uncollected fuel and purchased power costs. That PSA adjustor expired at the end of the July 2008 billing cycle. APS seeks approval to implement a new Interim Base Rate Surcharge of the same amount, which APS indicates would produce annual revenue of approximately $115 million. APS' response to Staff Interim 1.13[2] states that the purpose of the surcharge would be to ameliorate the detrimental impact of the Company's rising non-fuel costs until the Commission has the opportunity to enter an order on the Company's permanent rate request in the underlying general rate case. If granted, any interim rates would be subject to refund with interest, pending the Commission's final decision in APS' general rate case.

On August 6, 2008, in Decision No. 70454, the Commission approved a request by APS for its parent, PNW, to infuse equity by up to $400 million. As stated at page 2 of that decision: "PNW indicates that it intends to infuse a total of up to $400 million into APS in the year 2008, from the proceeds of PNW common stock sales. APS does not anticipate that the $400 million equity investment will impact APS' cost of service and cost of capital in the foreseeable future. [1] APS currently has a rate case in progress under Docket No. E-01345A-08-0172." At page 3 of Decision No. 70454, the Commission stated that: "Authorization to increase equity by up to $400 million … would assist APS' efforts to maintain a balance of cost and financial risk in its capital structure while funding its capital expenditures." At page 4, the Commission approved the requested increase to equity "so long as such equity infusion is made on or before December 31, 2009."

[2] See Attachment RCS-2, page 15.

On July 16, 2008, a procedural schedule was established for APS' interim rate request that provides for Staff and intervenor testimony to be filed on August 29, 2008; APS rebuttal on September 8, 2008; and a hearing commencing on September 15, 2008.

On July 29, 2008, a procedural schedule was established for APS' general rate case, which provides, among other things, for Staff and intervenor direct testimony (other than rate design) to be filed on December 19, 2008; APS rebuttal on February 6, 2009; Surrebuttal on March 6, 2009; APS rejoinder on March 20, 2009; and a hearing commencing on April 2, 2009.

Q. Please briefly summarize APS' basis for its request for Interim Rates.

A. APS' application at various places[3] claims that, from the end of the September 30, 2005, test year used to set the Company's present rates in Decision No. 69663 (6/28/2007) to May 31, 2008, the Company has invested in over $1.7 billion for new facilities that are not reflected in current rates. APS' response to Staff Interim 1.13[4] states that the purpose of the surcharge would be to ameliorate the detrimental impact of the Company's rising non-fuel costs until the Commission has the opportunity to enter an order on the Company's permanent rate request in the underlying general rate case.

APS points to a number of factors as supporting its request for interim rates, including: its inability in recent years to earn its authorized return on equity (ROE); its recent actual and projected net cash flow, which requires access to outside financing; the poor stock price performance of its parent company, Pinnacle West Capital Corporation ("PNW" or "PWCC") compared with other investor-owned utilities; its bond ratings, which APS states are "currently among the lowest they can possibly be without being regarded as

[3] See, e.g., page 2, line 16; page 4, line 24; Brandt affidavit, page 5, line 25; etc.
[4] See Attachment RCS-2, page 15.

"junk"; and its Funds From Operations to Debt ("FFO/Debt") ratio, which APS asserts is the key financial metric examined by the credit rating agencies, and which measures the sufficiency of a company's cash flow to service both debt interest and debt principal over time. For APS' present "business profile" category, APS states that Standard & Poor's expects APS to maintain an FFO/Debt ratio of 18% to 28%.[5] If no rate increase is granted in the current general rate case, APS projects its FFO/Debt ratio will decline to 17.6% at the end of 2009 and to 16.6% at the end of 2010 under present rates, even with an equity infusion of $400 million.[6]

APS claims that the Company's financial condition will continue to deteriorate during the period of regulatory lag associated with the processing of a general rate case, and the Company will once again be on the brink of a downgrade to junk credit status in 2009 before the Commission will likely have ruled on its general rate application.[7] Pursuant to the Commission's time clock rules, A.A.C. R14-2-103(B)(11), APS has requested that the rates in its general rate application become effective no later than October 1, 2009.

B. Criteria for Interim Rate Relief

Q. In general, when is interim rate relief appropriate?

A. In my experience, interim rate increases can be appropriate if the Commission is unable to process a utility's base rate increase request in a timely manner, if the utility is experiencing an emergency, or if other special circumstances are present. By this statement, I do not mean to address Arizona's legal requirements for establishing interim rates. I am instead merely providing a layperson's observations based on my regulatory experience.

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[5] See, e.g., APS witness Brandt's affidavit at page 12, paragraph 26.
[6] Id.
[7] See, e.g., APS witness Brandt's affidavit, pages 18-19, paragraph 42.

Q. What schedule has been established for the processing of APS' general rate case?

A. A procedural schedule has been established in the general rate case which provides, among other things, for Staff and intervenor direct testimony (other than rate design) to be filed on December 19, 2008 and a hearing commencing on April 2, 2009. The parties are currently expecting that new base rates for APS established in the general rate case could go into effect as early as October 2009.

Q. What conditions could constitute an emergency?

A. An emergency could generally include circumstances that threaten or interfere with a Company's ability to provide safe and reliable service, such as insolvency or a sudden, unanticipated occurrence. Some conditions that could constitute a financial emergency include an inability to raise capital at reasonable terms, inability to meet required coverage ratios specified in bond indentures, a cash flow crisis, or an inability to pay current expenses.

Q. Is there any indication that the Commission either has been or will be unable to process APS' general rate application in a timely manner?

A. No. In fact, we are at the beginning of the process in that proceeding, and I see no reason at this time to expect that it will not be processed according to the established procedural schedule.

Q. Has Staff compiled a listing of emergency rate applications before the Commission since 1983?

A. Yes. Such a listing was compiled by Staff as Appendix A to Staff's closing brief in Docket No. E-01345A-06-0009, involving an application by APS for an emergency interim rate increase in 2006. For ease of reference I have included that listing in Attachment RCS-2, at pages 37-41.

Q. In Docket No. E-01345A-06-0009, what did Staff conclude from its analysis of prior applications for emergency rate increases before the Commission?

A. Staff concluded that the question of what qualifies as an emergency is largely an issue of fact for the Commission to decide. In Docket No. E-01345A-06-0009, Staff concluded that the facts in that case did not warrant emergency interim rate relief. The following quote from pages 3-4 of Staff's brief summarizes the evaluation by Staff in that proceeding:

> *Most emergency rate cases before the Commission in the past ten to fifteen years involved small water systems facing a crisis of being unable to provide adequate and reliable service without an immediate increase in rates. Many of the cases involved significant operational and maintenance deficiencies. See Decision Nos. 57841 (Mountain View Water Company) and 67990 (Sabrosa Water Company). Others involved water quality and regulatory compliance issues from other state agencies. See Decision Nos. 61833 (Far West Water Company) and 62651 (Thim Utility Company, E&T Division). The Commission, however, has also denied or partially denied applications for emergency rate relief. See Decision Nos. 57668 (E & R Water Company et. al.), 59250 (Mountain View Water Company) and 61930 (Vail Water Company). Appendix A lists several cases where the Commission has heard emergency interim rate relief cases, some of which have been cited above. In the majority of those cases where emergency interim rate relief was approved, the crisis defined by the company had already occurred or was occurring.*
>
> ...
>
> *The evidence in this case is that there is no threat of insolvency or a liquidity crisis if APS' request is not granted. (Tr. at 392). APS contends that the possible downgrade of its credit rating to junk status is the emergency at hand, and that this meets the criteria of an emergency set forth in the Arizona Attorney General's Opinion 71-17...Staff does not agree with APS that a downgrade is imminent based on what the credit rating agencies have stated in their written reports. In other words, a sudden change to APS' credit rating appears unlikely...And no evidence*

> *was presented that APS will not be able to continue providing adequate and reliable service before the permanent rate case is resolved. The public interest does not necessitate the granting of emergency interim rate relief requested by APS.*

Q. How does APS' present request for interim rates compare with its 2006 interim rate request?

A. The current APS request for an interim rate increase bears some similarities with Docket No. E-01345A-06-0009. Again, APS has focused concern on the potential for a credit ratings downgrade. One key difference between that 2006 APS emergency rate increase request and APS' current request for interim rates is that in Docket No. E-01345A-06-0009 a primary focus was on the operation of APS' Power Supply Adjustor ("PSA") mechanism and the potential under that mechanism, as it existed at that time, for growing deferrals of fuel cost. In APS' current application for interim rates, the operation of the PSA is not a significant concern, as I explain in a subsequent section of my testimony. APS' has instead focused its present request for Interim Rates on the alleged negative impact of regulatory lag as it applies to APS' recovery of plant investment.

C. Ordinary Regulatory Lag Does Not Justify APS' Requested Interim Rate Relief

Q. What has APS alleged about regulatory lag in relation to its request for interim rate relief?

A. APS has raised concerns about the impact of regulatory lag and has claimed that revenues from customer growth are occurring at an insufficient pace, absent periodic rate relief, to keep pace with the costs related to APS' capital investment.

Q. At page 2, lines 16-17, of its application APS has claimed that it has expended $1.7 billion for new facilities that are not reflected in current rates. Please discuss APS' capital expenditures and how they relate to APS' current rate base.

A. APS' response to Staff Interim 2.96(f) provided a breakout of the $1.7 billion by type of plant and period.[8] The $1.7 billion claimed by APS includes $297 million of capital expenditures beyond December 31, 2007, the end of the test year in the current rate case. Moreover, the APS capital expenditures do not directly translate into a rate base increase because during the same time frame Accumulated Depreciation, which is an offset to gross plant, is also growing significantly. Consequently, the $1.7 billion is not an appropriate basis for determining the increase in APS' net plant in service between the end of its last test year and the end of the test year in the pending general rate case. The $1.7 billion, in essence, does not represent the net amount of jurisdictional rate base increase that has been financed by investors. In fact, it significantly overstates that amount.

Q. Through December 31, 2007, by how much had APS' rate base grown?

A. Based on a preliminary review of APS' current general rate case application, a comparison between the rate base specified in Decision No. 69663 from APS' last rate case, which had used a test year ending September 30, 2005, through the end of the test year in the current rate case, December 31, 2007 (without pro forma adjustments), APS' jurisdictional rate base has grown by approximately $538 million.

Q. Do these circumstances require that APS should be granted interim rate relief?

A. No. Although these factors should be examined in the general rate case, they do not necessitate interim rate relief within the circumstances of this case. Regulatory lag is an ordinary and anticipated feature of regulation. One of the useful functions of regulatory

[8] A copy of that response including APS13341 (the response attachment) lists the capital expenditures by plant type by period) is included in Attachment RCS-2, pages 2-10.

lag is to place financial responsibility upon the utility for fluctuations in costs between rate cases. The regulatory lag feature of Rate Base/Rate of Return regulation is essential to effective and efficient operation of such a regulatory régime. Because of the lag between placing new plant into service and obtaining rate recognition of such plant, the utility may bear the cost of new plant additions temporarily. This can encourage management to emphasize cost control to a higher degree than might be expected if cost responsibility for plant additions during the periods between rate cases were shifted away from the utility and onto ratepayers. In evaluating plant additions, the Company should conduct a cost-benefit analysis to determine if there is a business case for implementing the plant additions on the time frame budgeted by the Company. If the case is compelling and the project is cost-justified, no additional special ratemaking treatment is needed. If the project is not cost-justified or the benefits are too speculative to warrant the commitment of funds, it may be prudent to delay or avoid the related capital expenditures. These incentives that are currently in place would be lessened if ordinary regulatory lag began to be utilized by Arizona utilities as a justification for interim rate increases. Absent some emergency or other exceptional circumstance, ordinary regulatory lag by itself does not warrant the extraordinary relief of an interim rate increase.

Q. Is there merit to APS' claim that its revenues from customer growth are growing at an insufficient pace to keep up with the costs of APS' capital investment?

A. There is no way to know for certain without a full rate case investigation. Of course, there is not sufficient time to conduct such a thorough investigation in the timeframes of an interim rate case. It is worth noting that the investigation conducted by Staff in APS' last general rate case, Docket No. E-01345A-05-0816, concluded that there was no merit to APS' allegations that the cost of its customer growth exceeded the revenues generated by that growth. Commission Decision No. 69663 in APS' last rate case refers to the audit performed by Staff and the findings. For instance, at page 61 of that Decision, the last paragraph speaks to the Staff's audit and states in part that "Staff's audit of the Company's current rates shows that the non-fuel costs are being recovered, contrary to APS' claim that the cost of customer growth is greater than the revenues generated by that growth."

Q. Has APS raised similar issues with respect to regulatory lag in its current general rate case?

A. Yes. APS has raised issues associated with regulatory lag in its pending general rate case and has claimed that revenue increases resulting from customer growth are unable to keep pace with costs related to APS' capital spending. For example, APS has asked for an attrition adjustment of $79.3 million related to regulatory lag.

Q. Does Staff intend to examine issues raised by APS with regard to regulatory lag in the general rate case?

A. Yes. Staff has not completed its detailed review of APS' base rate application; nonetheless, Staff is not at this time convinced that APS' requested attrition adjustment is appropriate. Moreover, Staff believes that such issues can be best addressed in the context of the general rate case and that ordinary regulatory lag, by itself, does not necessitate an interim increase while that case is being processed.

D. Alleged Emergency Circumstances

Q. What emergency circumstances has APS alleged?

A. Pages 18-19 of APS witness Brandt's affidavit claims that: "… notwithstanding proactive efforts from the Company and Pinnacle West, APS' credit metrics will fall into junk credit range during the course of the Company's rate proceedings, before the Commission is likely to grant the much-needed rate relief. I firmly believe that the Company will more than likely be downgraded to junk during the pendency of the general rate case proceedings without interim relief." In response to Staff Interim 2.97, APS stated that: "While the Company hopes that it is able to continue to provide safe and reliable electric service to customers in 2008 and 2009 and intends to do so, the Company's interim base rate request is intended to support its overall financial health so that its ability to offer reliable electric service will not be jeopardized in the future."[9]

Q. Is APS currently experiencing an "emergency"?

A. No. APS has not identified any sudden or unanticipated circumstance affecting its ability to offer reliable electric service that would justify an interim rate increase.

Q. Has APS demonstrated that it cannot continue to provide safe, reasonable and adequate service without an interim rate increase?

A. No. Staff Interim data request 2.97[10] asked APS: "Without any interim rate increase, will APS be able to provide safe and reliable electric service to its customers in 2008 and 2009? If not, explain fully why not." APS' response stated that:

> *While the Company hopes that it is able to continue to provide safe and reliable electric service to its customers in 2008 and 2009 and intends to do so, the Company's interim base rate request is intended to support its overall financial health so that its ability to offer reliable electric service will not be jeopardized in the future.*

Unless there are unanticipated unforeseen events that occur during that time frame, the information reviewed by Staff would indicate that APS should be able to continue to provide safe, reasonable and adequate service without an interim rate increase while the APS general rate case is being processed.

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[9] A copy of that response is reproduced in Attachment RCS-2, page 48.
[10] See Attachment RCS-2 at page 48.

Q. Is APS currently experiencing a "financial emergency"?

A. No. APS is not currently experiencing a financial emergency. Staff's analysis reveals that APS has been and continues to be able to obtain financing. As explained in my and Staff witness Parcell's testimonies, APS is not currently experiencing a financial crisis and is not facing a cash flow emergency. As acknowledged in response to Staff Interim 2.76, without interim rates, APS does <u>not</u> believe it would be facing a cash flow emergency in 2008 or 2009. APS' response to that request[11] states: "No. The Company has $900 million in committed credit facilities available to it through 11/2010."

Q. What are APS' current bond ratings?

A. APS' response to data request Staff Interim 2.50[12] (among others) shows that APS' current long term debt ratings are:

S&P: BBB-
Moody's: Baa2
Fitch: BBB

Q. Does a downgrade of APS' credit rating appear imminent or probable during the processing of APS' general rate case?

A. No.

Q. Has Standard & Poor's discussed how APS' rating of BBB- relates to certain financial performance metrics?

A. Yes. This is discussed by S&P on the second page of its January 24, 2006 report.[13] APS' filing and testimony suggest that one particular financial metric, funds from operation as a

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[11] See Attachment RCS-2, page 33.
[12] See Attachment RCS-2, page 12.
[13] See Attachment RCS-2, pages 16-18.

percent of total debt ("FFO/Debt"), would cause the rating agencies to downgrade its credit standing to "junk" status.[14] However, while FFO/Debt is an important metric, this one measure by itself is not determinative of a bond rating. The January 24, 2006, S&P report, for example, explains that:

> *FFO to total debt is an important metric for Standard & Poor's, and at a business profile of '6' (on a 10-point scale where '1' is excellent and '10' vulnerable), it reflects a below-investment-grade performance. For the 12 months ending Sept. 30, 2005, FFO interest coverage was 3.3x, which is reasonable for the current rating. Adjusted total debt to total capitalization was 53.1% and is solid for the current rating.*

Thus, S&P reviews a number of financial metrics in the analytical process of establishing its ratings, and APS' other ratios, such as FFO interest coverage and debt to total capitalization, were found to be reasonable or solid for the current rating. Staff witness Parcell presents additional discussion regarding credit rating agency use of financial metrics in his prefiled Direct Testimony.

A more current S&P Ratings Direct report, dated June 25, 2008[15], indicated, among other things, that:

> *Standard & Poor's Rating Services today affirmed the 'BBB-' corporate credit rating assigned to Pinnacle West Capital Corporation (PWCC) and its utility, Arizona Public Service. The outlook is stable. The consolidated credit ratings of PWCC primarily reflect the operations of its largest subsidiary, APS, a regulated, electric utility serving about 1.1 million customers within its service territory, which spans roughly two-thirds of Arizona and includes about half of the Phoenix MSA. We view the business profile of PWCC and APS to be 'strong'. While the company continues to benefit from a number of favorable attributes including a good service territory, a reasonably balanced power supply portfolio and*

[14] See, e.g., APS' Application at pages 6-7.
[15] APS13070, Attachment RCS-2, pages 19-23.

a good PSA. However, APS' continues to face significant regulatory challenges.

...

We view the financial profile of PWCC and APS to be 'aggressive', which reflects: year-end debt to total capitalization of 57% (adjusted for items such as power purchases and operating leases); heavy capital spending that is expected to drive negative free operating cash flow for the foreseeable future; cash flow weakness as a function of protracted rate cases; and, while modest, the presence of unregulated activities, which can be unpredictable in their earnings contributions.

Because the preponderance of cash flows for consolidated operations stems from APS, we expect financial performance will continue to be heavily dependent on regulatory outcomes. The conclusion of APS' last general rate case in June 2007 (filed in November 2005 and revised in early 2006) provided the company with mechanisms to recover legacy deferrals and speed the recovery of fuel costs going forward. This rate relief, in place for the last half of 2007, assisted the company in maintaining credit metrics roughly in line with past performance. Funds from operation (FFO) to total debt was about 16% at year-end, with FRO interest coverage around 4x. On a trailing 12-month basis the company's performance has been slightly above these levels, due in part to the federal tax stimulus package approved by the U.S. Congress earlier this year, which is expected to increase deferred taxes (which is added back to FFO and this increase this total).

We expect APS to be in more or less continuous rate case mode for the next few years. Given APS' capital spending program, forecasted to be about $1.1 billion annually through 2010, the utility will need to file regular general rate cases to manage recovery of its investment. The use of a historical test year in Arizona, coupled with the fact that fully litigated rate cases take between 18 to 24 months to complete, is expected to result in no meaningful improvement in financial performance through 2009 and possibly beyond, depending on the timing and the outcome of the company's current rate case.

A complete copy of that S&P report is included in Attachment RCS-2, pages 19-23, to my testimony. Additionally, a complete copy of Standard & Poor's 2008 Corporate Ratings

Criteria[16] is included in Attachment RCS-3, and a copy of S&P's Ratings Direct, "U.S. Utilities Ratings Analysis Now Portrayed In The S&P Corporate Ratings Matrix" dated 11/30/2007 is included in Attachment RCS-2, at pages 61-64.

Q. What "financial risk indicative ratios" are listed in Standard & Poor's 2008 Corporate Ratings Criteria, for a utility, such as APS, with an "aggressive" financial risk profile?

A. Referring to Attachment RCS-3, page 20 lists the ranges of financial risk indicative ratios for a corporation or a U.S. utility, such as APS, with a business risk profile of "strong" and a financial risk profile of "aggressive." A similar listing of ranges indicated by S&P for U.S. Utilities appears in Attachment RCS-2, page 63. The ranges listed by S&P for the applicable "financial risk indicative ratios" are:

S&P 2008 Corporate and U.S. Utilities Ratings Criteria		**U.S.**
Financial Risk Indicative Ratios*	**Corporate[1]**	**Utilities[2]**
BBB- Range		
Cash flow (funds from operations/Debt) %	15-30	10-30
Cash flow (FFO/interest) (times)		2.0-3.5
Debt leverage (Total debt/Capital) %	45-55	45-60
Debt/EBITDA (times)	3.0-4.5	
*Fully adjusted, historically demonstrated, and expected to continue consistently Business risk profile "solid"; financial risk profile "aggressive"		
[1] Standard & Poor's 2008 Corporate Ratings Criteria		
[2] Source: Standard & Poor's Ratings Direct, 11/31/2007; U.S. Utilities Ratings Analysis Now Portrayed in the S&P Corporate Ratings Matrix		

[16] A copy of that report was provided by APS in response to Staff Interim 2.82, and has been identified by APS as "APS12977".

Q. Has APS provided information on what impact various levels of interim and permanent rate increases would have on its FFO/Debt ratio?

A. Yes. Staff data requests 2.59 and 2.60[17] asked APS to run various scenarios of interim and permanent rate increases, and to calculate the impact on its FFO/Debt ratio, among other things. The following table summarizes those results from APS' second supplemental response to Staff Interim 2.59[18]:

APS Calculated FFO/Adjusted Total Debt Under Various Scenarios

		Estimated FFO/Adjusted Total Debt		
Case #	Description[a]	2008	2009	2010
1	100% of $115M Interim Nov'08, 100% of Non-Fuel Base Rate Increase 10/1/09 (5%)	23.3%	20.7%	21.3%
2	100% of $115M Interim Nov'08, 50% of Non-Fuel Base Rate Increase 10/1/09 (5%)	23.3%	20.2%	18.9%
3	50% of $115M Interim Nov'08, 100% of Non-Fuel Base Rate Increase 10/1/09 (5%)	23.2%	19.9%	21.0%
4	50% of $115M Interim Nov'08, 50% of Non-Fuel Base Rate Increase 10/1/09 (5%)	23.2%	19.4%	18.7%
5	No $115M Interim Nov'08, 100% of Non-Fuel Base Rate Increase 10/1/09 (5%)	23.0%	19.1%	20.8%
6	No $115M Interim Nov'08, 50% of Non-Fuel Base Rate Increase 10/1/09 (5%)	23.0%	18.7%	18.5%
7	50% of $115M Interim Nov'08, 75% of Non-Fuel Base Rate Increase 10/1/09 (7.5%)	23.2%	19.7%	19.8%
8	50% of $115M Interim Nov'08, 25% of Non-Fuel Base Rate Increase 10/1/09 (2.5%)	23.2%	19.2%	17.6%
9	No $115M Interim Nov'08, 75% of Non-Fuel Base Rate Increase 10/1/09 (7.5%)	23.0%	18.9%	19.7%
10	No $115M Interim Nov'08, 25% of Non-Fuel Base Rate Increase 10/1/09 (2.5%)	23.0%	18.4%	17.4%

Notes
[a] All case scenarios shown in this table also reflect an assumed fuel-related increase effective 10/1/09 (7%)

As shown in the above table, with no interim increase and assuming 50% of its base rate increase is granted with rates effective October 1, 2009, APS' FFO/Debt ratio is expected to be 23.0% in 2008, 18.7% in 2009, and 18.5% in 2010, all of which are within Standard & Poor's BBB- "investment grade" range for a company with APS' business and financial

[17] See Attachment RCS-2, pages 57 and 60, respectively.
[18] A copy of that response and the "Case Summaries" attachment from that response is included in Attachment RCS-2, pages 58-59. APS's full response also included additional detailed calculations for amounts contained in the "Case Summaries."

risk profile of 15% to 30% as stated in the S&P 2008 Corporate Ratings Criteria[19] and are within the 10% to 30% range specified in S&P's U.S. Utilities Ratings Analysis.[20] These are also above the range of 18.0% to 28.0% that APS witness Brandt states that "S&P expects APS to maintain."[21] This suggests that APS does not need any interim rate increase in order to keep its FFO/Debt ratio in a range appropriate for APS' current bond ratings through 2010. In other words, APS does not need any interim rate increase in 2008 or 2009 in order to keep its FFO/Debt ratio within an "investment grade" range. The level of base rate relief in the general rate case will affect APS' FFO/Debt ratio in 2009 and 2010.

Q. **Would the interim rate relief that APS has requested necessarily prevent future downgrades of the Company's debt ratings?**

A. No.

Q. **Are there other factors or events that could cause future downgrades of the Company's debt ratings?**

A. There are at least two reasons why the interim and refundable rate relief that APS has requested would not necessarily prevent future downgrades of the Company's debt ratings. First, any interim rate increases granted in this proceeding would be subject to refund. If it is ultimately refunded, temporary refundable rate relief would thus only tend to postpone, and not prevent, further bond downgrades. Second, other factors, such as a sustained, unscheduled outage at the Palo Verde nuclear plant or one of APS' coal-fired generating facilities during a peak demand period could result in a downgrading. For example, Fitch's January 30, 2006 report[22] mentions the operational risk and asset

[19] See Attachment RCS-3, APS12977, page 20 of 107.
[20] See Attachment RCS-2, page 63.
[21] See Brandt June 6, 2008 affidavit , page 12, line 11.
[22] Provided in response to Staff interim 2.50 and included in Attachment RCS-2, at pages 24-25.

concentration of the Palo Verde nuclear plant as a concern and states that: "The facility has experienced intermittent operating problems over the past year and a sustained, unscheduled outage at the plant could lead to further negative rating actions."

Q. Would APS' requested interim rate relief likely result in a bond rating upgrade?

A. No. APS' requested interim rate relief would not likely result in a bond rating upgrade. An interim rate increase is not anticipated to result in an upgrade of APS' debt ratings. Nor does APS believe that its requested base rate increase would result in upgraded credit ratings. APS witness Brandt's direct prefiled testimony at page 67, indicates that APS' base rate increase request of $278.2 million of net revenues in the pending general rate case "will only allow the Company to maintain its current BBB- rating through at least 2010, requiring additional rate filings thereafter as APS' spending needs continue and rise and the threat of downgrade to junk persists." Moody's July 28, 2008 Credit Opinion[23] stated: "APS' rating is not likely to be revised upward in the near-to-medium term." Standard & Poor's June 25, 2008 Ratings Direct[24] concluded "we see little potential for positive movement in the ratings outlook." Consequently, an upgrade of APS' debt ratings is not anticipated.

Staff Interim 2.56 asked APS to: "Provide all quantitative analysis that APS has concerning the amount of additional annual revenues it would take to raise its bond rating up by one step."[25] APS' response states:

> *APS has not prepared such quantitative analyses. The Company's interim rate request and general rate case request are both needed in order to maintain current ratings levels and would not, in and of themselves, raise its ratings by any degree.*

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[23] APS13051, at page 5 of 6; a copy is reproduced in Attachment RCS-2, pages 42-27.
[24] APS13070, at page 4 of 5, a copy is reproduced in Attachment RCS-2, pages 19-23.
[25] See Attachment RCS-2, page 26.

As explained elsewhere in my testimony and in additional detail in the testimony of Staff witness Parcell, a particular FFO to Debt ratio does not, of itself, dictate a bond rating. Moreover, as shown in Attachment RCS-2, pages 19-23, Standard & Poor's most recent report, dated June 25, 2008, acknowledges that: "The use of a historical test year in Arizona, coupled with the fact that fully litigated rate cases take between 18 to 24 months to complete, is expected to result in no meaningful improvement in financial performance through 2009 and possibly beyond, depending on the timing and the outcome of the company's current case." In that report, S&P lists the outlook for APS as "stable" with the following explanation:

> *The stable outlook reflects our expectation that consolidated cash flow volatility has been tamped down by the ACC's approval of a stronger PSA that speeds recovery of fuel costs, but consolidated financial performance will continue to be challenged by regulatory lag at APS, which could be moderated by APS' pending interim rate request. The stable outlook is premised on no meaningful adverse changes in the company's business risks and continued financial performance that is not significantly weaker than 2007 results. Equity issuances will be expected to balance the capital structure of the company as APS continues to invest heavily in infrastructure. Ratings could be lowered to speculative grade if the company is not able to overcome the challenge of ensuring timely recovery of its prudently incurred costs through rate increases approved by the ACC. Given these challenges, and that presented by NRC scrutiny of Palo Verde, we see little potential for positive movement in the ratings or outlook.*

Q. Has APS' debt been downgraded to "junk" status?

A. No. APS' debt is still investment grade.

Q. Has APS identified how its financing costs could increase if its credit rating were downgraded to below investment grade status?

A. Yes. APS' response to Staff Interim 2.55 has identified $443.9 million to $889.5 million of total increased interest cost for the ten-year period 2010 through 2019 associated with a below investment grade debt rating, but Staff has not verified these numbers.[26]

Q. How are a utility's interest costs charged to ratepayers?

A. In general, a utility's financing costs for debt are reflected in the weighted cost of debt in the capital structure. The debt cost is multiplied by the jurisdictional rate base and ratepayers pay for the interest cost as one of the components of the utility's cost of capital. Depending on how the utility accounts for them, some borrowing costs, such as bank fees, may be included in operating expenses.

Q. Has APS issued debt since its bond rating was downgraded from BBB to BBB- by Standard & Poor's?

A. Yes. As indicated in APS' response to Staff Interim 2.71[27], APS has issued $400 million of long-term debt since S&P downgraded it to BBB- on December 21, 2005.

Q. Was the cost of that debt higher than if APS had maintained a BBB bond rating from S&P?

A. Yes. APS' response to Staff Interim 2.71(b)[28] states that:

> *If APS had had a bond rating of BBB at the time the amount referred to in subpart (a) was issued the coupon on these two tranches would have been approximately 6.20% and 6.825% respectively. This would have resulted*

[26] A copy of that response is included in Attachment RCS-2, pages 27-30.
[27] A copy of that response is included in Attachment RCS-2, page 31.
[28] Id.

in interest expense savings of $1.25 million and $2.25 million over the life of the bonds.

Q. If APS' annual borrowing costs increase by $1 million, would that necessarily result in $1 million of additional annual financing costs to ratepayers?

A. No. However, if a utility's borrowing costs increase, eventually ratepayers may be required to pay for some portion of the increased costs when they are recognized in a rate case.

Q. Would a downgrading of APS' debt to "junk" status be a desirable outcome?

A. No, it would not.

Q. Does it appear imminent or probable that APS' debt will be downgraded to "junk" status if the $115 million interim rate increase requested by APS is not granted?

A. No, it does not. APS' debt is still investment grade and the three credit rating agencies have listed their outlook for APS and PNW as "stable." See Attachment RCS-2 for copies of recent credit rating agency reports.

Q. Have any credit rating agencies announced that APS' debt would be downgraded if APS' request for interim rates were to be denied?

A. According to APS' response to data request Staff Interim 2.27(b)[29] none have.

[29] A copy of that response is included in Attachment RCS-2, page 32.

Q. Has APS provided proof that granting its requested interim rate increase of $115 million would result in a cost savings to ratepayers?

A. No. Avoiding a downgrading to "junk" status would save ratepayers significant amounts of future financing costs; however, APS has not demonstrated that its requested interim rate increase is necessary in order to do that.

Q. Has APS defaulted on any bond indenture or credit arrangements?

A. APS has indicated no. The response to Staff Interim 2.39[30] states that:

> *There are two provisions in APS' credit arrangements that address minimum financial ratios. The first one is the requirement that APS maintain an Interest Coverage of at least two times, and the second one requires that the amount of debt does not exceed 65% of total capitalization.*

That response also lists events of default. Notably, APS' application or testimony does not claim that a default has occurred. Nor do APS' responses to Staff data requests or the APS SEC filings that I have reviewed indicate that a default has occurred. A default would tend to be a "significant event" and would thus require reporting by APS and its parent company on SEC filings.

Q. Has the Commission approved increases to APS' borrowing and equity?

A. Yes. In 2007, the Commission approved an increase to APS' borrowing (Decision No. 69947) and, on August 6, 2008 approved an equity infusion of $400 million from APS' parent, Pinnacle West (Decision No. 70454).

[30] See Attachment RCS-2, page 14.

Q. How has S&P described APS' short and long-term borrowing?

A. As recognized in Standard & Poor's June 25, 2008 Ratings Direct[31]:

> *In October 2007, APS received approval from ACC to increase its authorized short-term debt borrowing capacity by $500 million, and long-term debt borrowing capacity by $1 billion. This will help address the needs of a growing customer base, and the increasing requirement for natural gas and purchased power.*

In that report, S&P also observed that:

> *APS had $682 million available under its two unsecured revolving credit facilities, $400 million of which expires in December 2010, and $500 million in September 2011.*[32]

Concerning its expectations for APS' cash flow and the maturing of debt obligations, S&P further observed that:

> *Discretionary cash flow is expected to be negative for 2008 due to APS' capital expenditure plans. Excluding the remarketing of APS' pollution control debt, neither PWCC nor APS has any significant debt obligations maturing until 2011.*[33]

Q. In 2007 and 2008, did APS experience difficulties in issuing commercial paper?

A. Yes. Due to the volatility in the credit markets resulting from the sub-prime mortgage crisis, APS' ability to issue commercial paper was impacted in August and December 2007.[34] As stated in APS' response to Staff Interim 2.24(b), throughout 2008 APS' ability to issue commercial paper was also impacted.

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[31] APS13070, at page 4 of 5; see Attachment RCS-2, pages 19-23, for a complete copy.
[32] Id.
[33] Id.
[34] See Attachment RCS-2, page 34 and page 13, paragraph 29 of APS witness Brandt's June 6, 2008, affidavit.

Q. Despite not being able to issue commercial paper, was APS able to obtain short term borrowings in 2007 and 2008?

A. Yes. APS' response to Staff Interim 2.24 states that in each instance, APS borrowed under its revolving credit facilities which currently have similar pricing to commercial paper.

Q. Has the Commission also recently authorized APS' parent, PNW, to infuse additional equity into APS?

A. Yes. The Commission's action on August 6, 2008 in Decision No. 70454 authorizes APS' parent, PNW, to infuse a total up to $400 million of equity into APS. In Docket No. E-01345A-08-0228 PNW indicated that it intended to infuse up to $400 million into APS in the year 2008.

Q. What was the stated basis for approving that equity infusion?

A. In that docket, APS indicated that it is facing substantial capital needs in 2008 and the foreseeable future and the requested equity investment is necessary to allow APS to maintain current investment grade credit and to improve financial stability. Consequently, by authorizing that equity infusion in Decision No. 70454, the Commission has already provided APS with a means whereby APS and its parent, PNW, can help maintain their current investment grade credit and improve financial stability during the pendency of APS' current general rate case.

Q. When does APS anticipate the equity infusion from PNW to occur?

A. APS' response to Staff Interim 2.19(a)[35] states: "We expect PNW to issue up to $400 million of equity before year-end 2009 and immediately infuse the proceeds into APS."

[35] A copy of that response is included in Attachment RCS-2, page 35.

Q. Does the timing of the infusion affect APS' financial ratios, such as FFO/Debt?

A. Yes. As explained in APS' response to Staff Interim 2.19(b): "The debt level will increase if there is no equity infusion which will decrease FFO/Debt by approximately 2%. Attached as APS13333 is an approximation of the FFO/Debt impact."[36] If APS is truly concerned about its financial ratios, obtaining the equity infusion from PNW sooner, rather than waiting to year-end 2009, would be one step that APS and its parent, PNW, could take to help address their own concerns about APS' financial ratios during the pendency of APS' current general rate case.

Q. Please summarize Staff's evaluation of APS' financial condition.

A. APS' debt is investment grade. Investment rating agencies such as Standard & Poor's, Moody's and Fitch rank APS' debt as investment grade, and those agencies have listed their outlook for APS and PNW as "stable." Moreover, other key financial metrics for APS appear solid for its business profile. APS' response to Staff Interim 2.50 at APS13014[37] shows that APS' current long-term debt ratings are:

S&P: BBB-
Moody's: Baa2
Fitch: BBB

Moreover, APS' FFO/Debt ratio is currently well within the 15% to 30% range specified by Standard & Poor's for a BBB- rating for a corporation with a "strong" business risk profile and an "aggressive" financial risk profile[38] and within the 10% to 30% range for a U.S. utility with that business and financial risk profile.[39] APS has projected its FFO/Debt

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[36] See APS13333 at Attachment RCS-2, page 36.
[37] See Attachment RCS-2 at page 12.
[38] See Attachment RCS-3 at page 20.
[39] See Attachment RCS-2 at page 63.

ratio to be 23.0% in 2008 even without any interim rate increase.[40] Moreover, as Staff witness Parcell explains, the credit rating agencies look at other financial ratios and information; thus, a temporary dip in one financial metric, APS' FFO/Debt ratio, in 2009 below 18% will not necessarily result in a downgrade. APS and its parent, PNW, can help themselves maintain an FFO/Debt ratio in the "investment grade" range by making the Commission-authorized $400 million equity infusion into APS sooner, rather than later.[41]

E. Whether APS Requires an Interim Rate increase During the Processing of its General Rate Case

Q. Does APS need an interim rate increase during the processing of APS' general rate case?

A. No. Based on the information provided by APS and the analysis performed by Staff, APS' financial condition appears to be sound enough to not require an interim rate increase during the processing of its general rate case.

Q. Does the operation of the Power Supply Adjustor provide a justification for granting interim rate relief during the processing of APS' general rate case?

A. No. Unlike APS' request for an emergency rate increase in 2006, APS' current request for interim rates is driven not by issues related to the collection of fuel and purchased power costs, but by other factors. Indeed, APS witness Brandt's direct testimony, at page 6, acknowledges that Decision No. 69663 (6/29/2007) went a long way towards solving much of the Company's fuel cost recovery problem. Standard and Poor's, as recently as June 25, 2008, commented that APS "continues to benefit from a number of favorable attributes including a good service territory, a reasonably balanced power supply portfolio

[40] See Attachment RCS-2, at pages 36 and 58-59.
[41] See, e.g., Attachment RCS-2 at page 36.

and a good PSA."[42] My review of the evidence to date indicates that the operation of APS' PSA is not contributing to any compelling need for an interim rate increase in the current proceeding.

Q. Do APS concerns about regulatory lag provide a justification for granting interim rate relief during the processing of APS' general rate case?

A. APS has raised allegations about the negative impacts of regulatory lag. Specifically, APS claims that its revenues from customer growth are growing at an insufficient pace, absent periodic rate relief, to keep pace with the costs related to its capital investment. Of course, as discussed above, there is no reliable way to evaluate this claim in the context of an interim rate case because a thorough rate case investigation cannot be completed in the allotted timeframe. Furthermore, the investigation conducted by Staff in APS' last rate case, Docket No. E-01345A-05-0816, concluded that APS' claims in this regard (*i.e.*, that the cost of customer growth was greater than the revenues generated by that growth, thereby causing the Company's rates to be inadequate) were not supported by the evidence.[43] This does not mean that Staff's investigation will reach the same result in the current general rate case; nonetheless, it is important to bear in mind that the Company's allegations are not always borne out by the investigation results.

Even if a full rate case investigation could be completed within the available timeframe of the interim case, ordinary regulatory lag is not the sort of circumstance that, by itself, would justify interim rate relief.

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[42] Standard & Poor's Ratings Direct, June 25, 2008, Arizona Public Service Co., APS13070, provided in response to Staff Interim 2.6, included in Appendix RCS-2 at pages 19-23

[43] See, e.g., Staff's reply brief (2/16/2007) at pages 7-10; also see Decision No. 69663 at pages 49-68.

Q. Has APS demonstrated that, without an interim rate increase, its financial status would be impaired, or that it would otherwise be prevented from attracting capital at fair and reasonable terms?

A. No. Unless there are unanticipated unforeseen events that occur during that time frame, the information reviewed by Staff would indicate that APS' financial status would not be impaired and that APS should be able to continue to attract capital at fair and reasonable terms while the APS general rate case is being processed.

Q. Has APS proved that a $115 million interim rate increase is needed at this time?

A. No. APS has not demonstrated that its requested interim rate relief would:

- prevent future downgrades of APS' debt ratings
- result in an upgrade of APS' debt ratings
- result in lower long-term costs for their customers, or
- be appropriate under the circumstances.

Q. Should the $115 million of interim relief requested by APS be granted?

A. No. After the Commission's actions in Decision No. 70454, and based on Staff's analysis and the current time-table for establishing new base rates for APS in the current APS general rate case, APS does not require a $115 million interim rate increase at this time.

F. An Alternative Basis for Determining an Amount of Interim Rate Increase for APS Should the Commission be Inclined to Grant an Increase

Q. Is Staff presenting the Commission with an alternative basis for determining an amount of interim rate increase for APS?

A. Yes. While Staff is not recommending an interim rate increase during the pendency of APS' general rate case, and Staff is not recommending any interim increase, Staff is presenting the Commission with an alternative basis for determining an amount of interim rate increase, should the Commission be inclined to grant one.

Q. Please describe the basis for Staff's alternative recommendation.

A. Staff's alternative is based on the growth in APS' jurisdictional rate base from Decision No. 69663 in APS's last rate case through the end of the test year in the current rate case December 31, 2007 (without pro forma adjustments). Based on the growth in jurisdictional rate base during that period, Staff's alternative would provide an interim rate increase of approximately $65 million. For comparative purposes, the $65 million would represent approximately 56.5% of the $115 million interim rate increase requested by APS.

Q. What test year is being used in APS' current general rate case?

A. A test year ending December 31, 2007 is being used in the rate case.

Q. What test year was used in APS' last general rate case?

A. A test year ending September 30, 2005 was used in APS' last rate case, Docket No. E-01345A-05-0816 et al.

Q. Has APS added net plant in service and increased its jurisdictional rate base after its last rate case through December 31, 2007?

A. Yes.

Q. How does the jurisdictional rate base for APS approved in Decision No. 69663 compare with APS' unadjusted jurisdictional rate base at December 31, 2007, as filed by APS in the current general rate case?

A. In Decision No. 69663, the Commission determined that APS' jurisdictional adjusted original cost rate base was $4.403 billion. In the current rate case, APS' filing at Schedule B-1, page 1, Column D, shows an unadjusted jurisdictional rate base of $4.941 billion. Based on the change in jurisdictional rate base from Decision No. 69663 through December 31, 2007, the end of the test year, this is an increase of approximately $538 million.

Q. Has Staff completed its verification of the unadjusted jurisdictional rate base at December 31, 2007, as filed by APS in the current general rate case?

A. No. Staff is in the early process of reviewing APS' general rate case filing. As part of the initial review, we have begun tracing the amounts of unadjusted rate base on APS' Schedule B-1 to the source documents, such as the Company's audited financial statements and supporting documentation; however, that process has not yet been completed. Staff has issued a number of data requests to APS to help facilitate this verification process.

Q. Has Staff reviewed APS' general rate increase filing in sufficient detail at this point to determine approximately what amount of permanent increase Staff would be recommending?

A. No. Not at this time. Staff's consultants, including myself, have just recently commenced the analysis of APS' general rate case filing. Staff anticipates having that analysis completed by the filing date specified in the general rate case for Staff's filing of direct testimony on revenue requirements. According to the current schedule, that date is December 19, 2008.

Q. Have you been able to determine what portions of the increase requested by APS in its general rate case are likely to not be controversial?

A. Not with a precise degree of accuracy. However, unless imprudence or accounting errors were to be found, a utility's net book plant, taken from its audited accounting records, would tend not to be controversial, whereas utility proposed pro forma adjustments, especially ones that are significantly different from those approved by the regulatory commission in the prior rate case, may tend to be controversial.

Q. Given the time frame provided for addressing APS' request for interim rates, how would you recommend that an amount of interim increase be determined?

A. Given the limited review time available to address a revenue requirement for interim rates, one method of providing for interim rates would be to recognize the increased investment in net plant that APS has experienced from its last rate case through December 31, 2007, the end of the test year in the current APS general rate case, and to base the interim rate increase on providing a return on that, at the last approved cost of capital.

APS had invested in net plant since the test year in its last rate case. A portion of APS' investment in net plant through December 31, 2007, the end of the test year in APS' current general rate case, has not yet been recognized for ratemaking purposes. The increase in jurisdictional rate base from Decision No. 69663 through December 31, 2007 could be used as a basis for determining an amount of interim rate increase in the current proceeding. If the Commission determines that it should grant APS an interim rate increase, I recommend an interim increase of approximately $65.2 million effective with the first billing cycle in November 2008, and contingent upon APS receiving the $400 million equity infusion from PNW by then.

Q. Why would you focus on net plant, rather than total capital expenditures, i.e., on gross plant?

A. Focusing on gross plant or total capital expenditures, rather than on net plant or net growth in jurisdictional rate base, would substantially overstate the net amount financed by investors. The major component of rate base is net plant. In deriving rate base, Accumulated Depreciation is subtracted from Plant in Service to derive net plant. Depreciation accruals, which continue each year, provide a source of funds supporting APS' investment in plant. As shown on Schedule E-2, line 4 of APS' filing, the Company recorded Depreciation and Amortization of $353 million in 2006 and $365.4 million in 2007. As shown on Schedule E-1, page 1, lines 1-3 of APS' filing, from 12/31/05 to 12/31/07, APS' gross Plant in Service (and held for future use) increased from $10.683 billion to $11.583 billion, an increase of approximately $899 million over that two-year period. Concurrent with that, however, Accumulated Depreciation also grew from approximately $4 billion as of 12/31/05 to $4.387 billion as of 12/31/87, for an increase of approximately $386 million. Using the information on APS' Schedule E-1, line 3, as an approximation of the growth in net plant, from 12/31/05 to 12/31/07, APS' net utility plant grew from $6.681 billion to $7.196 billion, an increase of approximately $514 million.

From another perspective, adjusted jurisdictional net plant for APS, as reflected in Decision No. 69663, was approximately $5.750 billion. Unadjusted jurisdictional net plant in APS' current rate case filing (at Schedule B-1, column D) is approximately $6.241 billion. This represents an increase in jurisdictional net plant of approximately $491 million.

Q. What amount of interim rate increase would you suggest in order to provide rate recognition of the increase in jurisdictional rate base that APS has experienced through December 31, 2007?

A. If the Commission determines that it should grant APS an interim rate increase, I recommend an interim increase in the amount of $65.2 million effective with the first billing cycle in November 2008, and contingent upon APS receiving the $400 million equity infusion from PNW by that time.

Q. Have you attached calculations showing how you derived that amount?

A. Yes. Supporting calculations for Staff's alternative basis for determining an amount of Interim Rate increase are presented in Attachment RCS-4.

Q. Please explain Attachment RCS-4.

A. Attachment RCS-4 is essentially a simplified revenue requirements model. Schedule A shows the amount of revenue increase. The net change in jurisdictional rate base from Decision No. 69663 to the unadjusted end-of-test-year amount from APS' Schedule B-1, column D, of $538 million, is multiplied by the cost of capital of 8.32% from Decision No. 69663, to derive operating income required of $44.753 million. Increased rate base produced an increased interest deduction, using the Commission's interest synchronization methodology, which decreased income tax expense and increased operating income by $5.212 million, as shown on Schedule A, line 4. The net change in operating income of $39.541 million is multiplied by the gross revenue conversion factor of 1.6491 to derive the alternative amount of interim rate increase of approximately $65.2 million.

Supporting calculations are included in Attachment RCS-4. Schedule A-1 shows the gross revenue conversion factor. Schedule B shows the change in jurisdictional rate base.

Schedule C shows the impact of interest synchronization. Schedule D shows the capital structure and cost of capital authorized in Decision No. 69663.

Q. Does a $65.2 million interim increase reflect any impact from APS pro forma rate base adjustments or a higher cost of capital than the Commission approved in Decision No. 69663?

A. No. Because APS' general rate case has not been reviewed in sufficient detail as of this time to ascertain what amount of permanent rate increase Staff would recommend, I have limited the rate base change to actual as of December 31, 2007 and have not included any APS-proposed pro forma adjustments. This amount also utilizes the same capital structure and cost of capital that the Commission approved in Decision No. 69663. Staff will evaluate and respond to APS' request for a higher cost of capital in the general rate case.

Q. Should the amount of interim rate increase be tied to a single financial ratio, such as FFO/Debt?

A. No. As discussed above, APS is not currently experiencing a financial emergency. Nor does a downgrade to junk status appear probable or imminent during the pendency of APS' current general rate case. As described on pages 16-21 of my testimony, even without any interim rate increase, APS's FFO/Debt ratio is projected to remain within the range established by S&P for APS' current debt rating and risk profile. Staff also cautions against basing any rate relief for APS on the results of a single financial ratio, such as FFO/Debt. As explained by Staff witness Parcell, financial ratios that are used by credit rating agencies are one item of information that APS has presented. Staff recommends against replacing the Commission's traditional ratemaking model of cost-based, rate-of-return regulation with a new model that would base utility rate increases on targeting one specific financial ratio, such as FFO/Debt.

Q. Is it necessary to tie the amount of an interim rate increase to an expired fuel surcharge?

A. No. The basis for the amount of interim rate increase requested by APS is tied to the approximately 4 mils per kWh of a PSA surcharge that expired in July 2008. Since that surcharge has expired, and has been removed from customer rates as originally intended upon full recovery of the surcharged costs, there is no need to now tie the amount of an interim rate increase to an expired fuel surcharge. Staff's analysis indicates that APS does not require an interim rate increase of $115 million at this time. Moreover, the amount of interim increase need not, and should not be, tied to the amount of the PSA surcharge that expired in July 2008.

Q. Have any credit rating agencies announced that APS' debt would be downgraded if APS' request for interim rates were to be granted in an amount substantially lower than the $115 million requested by APS?

A. According to APS' response to data request Staff Interim 2.27(c)[44] none have.

Q. If any refundable interim rate relief were to be granted in response to APS' current request, what safeguards are required?

A. I am not recommending that interim rate relief be granted to APS in this proceeding. However, if the Commission were inclined to grant APS some amount of interim rate relief, I am aware that it may be necessary for APS to post a bond.[45] Thus, granting an interim rate increase may result in an additional cost to APS and its ratepayers related to the cost of the surety bond or letter of credit.

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[44] A copy of that response is included in Attachment RCS-2, page 32.
[45] See, e.g., Cite Court of Appeals decision

Q. Has APS estimated what the cost of a surety bond or letter of credit would be?

A. Yes. In response to Staff Interim 2.74, APS estimates that the cost of a surety bond or a letter of credit would be approximately 1% of the face value.[46]

Q. Has APS indicated whether it would be willing to provide such a surety bond or other form of guarantee?

A. Yes. APS' response to Staff Interim 2.73[47] stated as follows:

> *Although APS does not believe that it is legally obligated or necessary to post a bond, APS would nonetheless be willing to provide a bond or a letter of credit guaranteeing the refunds, if ordered to do so by the Commission.*

Q. Is there a way to avoid the extra cost of a surety bond or letter of credit to APS and its ratepayers?

A. Yes. Such cost could be avoided by denying APS' request for an interim rate increase.

Q. Should APS be granted interim rate relief in the absence of the equity infusion?

A. No. No interim rate increase should be granted to APS until after the $400 million equity infusion approved by the Commission in Decision No. 70454 has been made. Put another way, any interim rate increase granted to APS should be contingent upon the completion of the $400 million equity infusion approved by the Commission in Decision No. 70454. This additional equity would assist APS' efforts to maintain a balance of cost and financial risk in its capital structure while funding its capital expenditures.

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[46] See Attachment RCS-2, page 49.
[47] See Attachment RCS-2, page 50.

G. Rate Design

Q. Please discuss the rate design proposed by APS for an interim rate increase.

A. APS witness Rumolo's affidavit presents three options for rate design for an interim rate increase:

1) Applying the same per kWh charge to all affected customers;
2) Applying a fixed percentage of base rates uniformly across all rate schedules; and
3) A two-step process, which would first assign the revenue requirement to customer classes (i.e., residential, general service, industrial, etc.) on an energy basis. For customers who are billed on a demand basis, the revenue increase would be converted to a per kW demand charge.

At page 5 of his affidavit, Mr. Rumolo concludes that each of the three options provides APS with the same level of interim rate relief and the Company does not have a preference for any one of the options.

Q. In APS' last general rate case, what rate design did Staff favor, and what generally did the Commission adopt?

A. In APS' last rate case, Docket No. E-01345A-05-0816 et al, for APS' new permanent rates, Staff generally favored a rate spread that reflects the results of the class cost of service study ("COSS"), as opposed to an across-the-board increase. Decision No. 69663, at page 76, indicates that the Commission generally adopted APS' rate design as modified by Staff and with an AECC proposal for transmission rate design agreed to by APS.

Q. For interim rates, does Staff have a preference between the three alternative methods for rate design proposed by APS?

A. The rate design for an interim increase should be simple and straight-forward to implement and should also facilitate being able to track and verify the revenue produced by the Interim Rate increase in case there is a need to make refunds. If any interim rate increase is granted, Staff recommends that the Interim Base Rate Surcharge use the same per-kWh charge for all affected customers.

Q. Does this conclude your testimony?

A. Yes, it does.

Attachment RCS-1
QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, PSC staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Washington, Washington, D.C., Wisconsin, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed was the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933*	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)

U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. - Partial and Immediate (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-7650	Consumers Power Company – Final (Michigan PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)
U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)

R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
R-860378	Duquesne Light Company Surrebuttal (Pennsylvania PUC)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102 T E-1032-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)
R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102 & U-1551-89-103	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and TC-91-040B	Intrastate Access Charge Methodology, Pool and Rates Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS & 911-67-WS	General Development Utilities - Port Malabar and West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)

R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR*	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)
Non-Docketed Staff Investigation	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed Staff Investigation	Delaware - Estimate Impact of Universal Services Issues (Delaware PSC)

PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)
E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)

Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016, Phase I	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)
97-12-020 Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)

Arizona Public Service Company
Docket No. E-01345A-08-0172
Attachment RCS-2
Copies of APS' Responses to Data Requests and Documents Referenced in the Direct Testimony and Schedules of Ralph C. Smith

ARIZONA CORPORATION COMMISSION
STAFF'S SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172-INTERIM RATES
JULY 31, 2008

Staff Interim 2.96 Mr. Rumolo's affidavit at page 2, lines 18-19 refers to the functioning of the Transmission Cost Adjustor ("TCA"). (a) Please explain in detail how the TCA addresses capital expenditures related to transmission. (b) If plant additions for transmission are not included in the TCA, explain fully why not. (c) How much of the $1 billion per year capital expenditures mentioned in the Brant affidavit (see, e.g., page 5, line 16 and elsewhere) is for transmission that would be included in the TCA? (d) How much of the approximately $1.7 billion that Mr. Brandt says APS spent from June 28, 2007 to May 31, 2008 on ACC-jurisdictional capital projects was for transmission? (e) How much of the approximately $1.7 billion that Mr. Brandt says (on page 5, line 25) APS spent from June 28, 2007 to May 31, 2008 on ACC-jurisdictional capital projects was for non-discretionary capital expenditures? (f) Please provide a breakout of the $1.7 billion by type of plant; for all completed projects, show the amount of plant additions by plant account. (g) Does APS consider transmission to be ACC-jurisdictional? If not, explain fully why not. (h) Does consider the costs that it recovers in the TCA to be ACC-jurisdictional? If not, explain fully why not. (i) During any months in 2007 or 2008 did APS have any deferrals relating to the TCA? If so, please show the deferred balances relating to the TCA in each month of 2007 and 2008, by account. If not, explain fully why not.

Response:

(a) and (b) Capital expenditures related to transmission are recoverable under the TCA to the extent that such expenditures are recoverable in the Company's wholesale transmission formula rate. The FERC-approved transmission formula rate recovers capital expenditures to the extent that the expenditure relates to a project that either already closed to service as of the yearly May 15th update to the FERC rates, or is projected to close to service in the then-current calendar year.

(c) Transmission expenditures vary between approximately $200 million per year and approximately $300 million per year for 2008 through 2010. The total forecast for transmission expenditures across this

ARIZONA CORPORATION COMMISSION
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E-01345A-08-0172-INTERIM RATES
JULY 31, 2008

Staff Interim 2.96

Response Continued:

period is approximately $800 million (see Exhibit DEB-3 from Mr. Brandt's Direct Testimony in the General Rate Case).

(d) Please note that the $1.7 billion discussed in Mr. Brandt's affidavit was spent from October 1, 2005 to May 31, 2008, and not from June 28, 2007 as described in the question. The period of October 1, 2005 to May 31, 2008 was chosen because it covers the time between end of the Test Year of the Company's last rate case (Decision No. 69663), and the date of Mr. Brandt's affidavit.

With that clarification, no transmission expenditures are included in the $1.7 billion discussed in Mr. Brandt's affidavit.

(e) See discussion above regarding the time period of the spending, and see the answer to Staff 2.12 for a discussion on discretionary versus non-discretionary capital spending.

(f) See attached spreadsheets showing 10/1/05 thru 5/31/08 expenditures (APS13341) and plant additions (APS13342).

(g) Since transmission costs are not included on the ACC jurisdictional Cost of Service Study (COSS), APS does not consider transmission costs to be ACC jurisdictional.

(h) See answer to (g) above. Although costs recovered through the TCA are paid by retail rate payers, the rates which drive the TCA are set by the FERC.

(i) APS has made no TCA specific deferrals. However, APS has reserved $1.4 million at the FERC jurisdictional level related to the difference between originally proposed rates and those ultimately settled upon as part of the FERC rate case. This reserve will be returned to customers in the calculation of the next FERC Formula Filing that will take effect in June 2009.

Witness: David Rumolo

APS CapEx from Test Yr ended 9/30/05 through 5/31/08

Excludes expenditures for Palo Verde Unit 1 Steam Generator Replacement

		A	B	C	D	E
		Actual 4th Quarter 2005	Actual 2006	Actual 2007	Actual, Jan - May 08	Total, Q405 - 5/31/08
1	Distribution	83	356	370	140	949
2	Generation excl PV U1 SG	35	176	353	149	713
3	Other (Corporate I/S, Facilities)	13	16	37	8	74
4	**Subtotal, excl Trans & PV U1 SG**	**131**	**548**	**760**	**297**	**1,736**
5	Transmission	21	112	137	65	335
6	Palo Verde Unit 1 Steam Generator	20	-			20
7	Total APS	172	660	897	362	2,091

APS Construction Expenditures
4th Quarter 2005 thru May 2008

	Q4 2005	2006	2007	Jan - May 2008	Total
Distribution					
Distribution Infrastructure	10	84	66	34	194
Cable Replacement	5	16	22	5	48
Other Reliability/Replacements	8	28	41	22	99
Customer Svc					
Meters	3	19	24	9	55
Transformers	7	40	50	14	111
Svc & Line Extensions	35	134	136	43	348
Strt Light / Dusk-Dawn	1	3	3	1	8
Schedule 3 Receipts recorded as CIAC	-	-	-	(1)	(1)
Distrib Gen'l Plant - I/S, Facilities	14	32	28	13	87
Total Distribution	**83**	**356**	**370**	**140**	**949**
Generation					
Nuclear excl Steam Gen Unit 1					
Nuclear Fuel	1	33	96	34	164
Power Plant Imprv - Nuc	11	31	42	16	100
Steam Gen Repl U3	2	9	41	-	52
Reactor Vessel Head Repl - U 1, 2, 3	-	-	7	3	10
Total Nuclear	**14**	**73**	**186**	**53**	**326**
Non-Nuclear					
4C	8	12	19	11	50
Cholla	4	48	88	55	195
Navajo	1	2	1	2	6
Redhawk	1	21	2	2	26
West Phx	5	14	7	6	32
Other Fossil excl Yuma Peaking Plant	2	6	3	3	14
Total Fossil excl Yuma Peaking Plant	**21**	**103**	**120**	**79**	**323**
Yuma Peaking Plant	-	-	47	17	64
Total Generation excl Steam Gen U1	**35**	**176**	**353**	**149**	**713**
Corporate facilities, I/S infrastructure, etc	13	16	35	7	71
APS M&T Info Systems	-	-	2	1	3
Total APS excl Transmission, SG-U1	**131**	**548**	**760**	**297**	**1,736**
Transmission	21	112	137	65	335
Steam Generator Replacement, PV Unit 1	20	-	-	-	20
Total APS	**172**	**660**	**897**	**362**	**2,091**

ARIZONA PUBLIC SERVICE COMPANY
Total Additions Between October 1, 2005 and May 31, 2008

Type of Plant	Account	4th Quarter 2005	2006	2007	May YTD 2008	Total
GENERAL & INTANGIBLE	(302) Franchises and Consents	105,618	524,292	43,181	-	673,091
GENERAL & INTANGIBLE	(303) Miscellaneous Intangible Plant	16,081,671	31,446,232	47,075,336	13,944,629	108,547,868
PRODUCTION	(311) Structures and Improvements	148,332	4,925,254	3,155,009	1,101,008	9,329,603
PRODUCTION	(312) Boiler Plant Equipment	2,965,180	15,171,714	50,682,418	43,885,621	112,704,933
PRODUCTION	(314) Turbogenerator Units	91,798	11,587,183	7,855,897	6,415,648	25,950,527
PRODUCTION	(315) Accessory Electric Equipment	686,204	5,577,757	4,496,952	3,030,608	13,791,521
PRODUCTION	(316) Misc. Power Plant Equipment	6,170	5,026,402	3,224,624	947,997	9,205,193
PRODUCTION	(320) Land and Land Rights	-	(414)	-	-	(414)
PRODUCTION	(321) Structures and Improvements	1,298,099	13,886,164	3,616,948	1,742,330	20,543,541
PRODUCTION	(322) Reactor Plant Equipment	69,993,552	8,102,499	3,503,210	76,198,800	157,798,062
PRODUCTION	(323) Turbogenerator Units	11,376,868	2,826,570	1,107,849	18,502,834	33,814,121
PRODUCTION	(324) Accessory Electric Equipment	(20,549)	835,332	291,094	2,042,367	3,148,244
PRODUCTION	(325) Misc. Power Plant Equipment	449,749	1,336,614	553,898	302,042	2,642,303
PRODUCTION	(326) Asset Retirement Costs for Nuclear Production	6,237,030	(17,956,065)	-	(22,821,144)	(34,540,179)
PRODUCTION	(337) Asset Retirement Costs for Hydraulic Production	-	-	(3,908,222)	-	(3,908,222)
PRODUCTION	(340) Land and Land Rights	0	(1,406)	-	-	(1,406)
PRODUCTION	(341) Structures and Improvements	764,874	2,267,221	937,327	665,366	4,634,788
PRODUCTION	(342) Fuel Holders, Products, and Accessories	71,693	(102,237)	3,825,125	521,318	4,315,899
PRODUCTION	(343) Prime Movers	172,906	(228,097)	4,306	64,196	13,311
PRODUCTION	(344) Generators	(221,275)	26,327,517	16,676,357	5,138,160	47,920,759
PRODUCTION	(345) Accessory Electric Equipment	(372,185)	1,741,462	3,892,823	64,654	5,326,754
PRODUCTION	(346) Misc. Power Plant Equipment	-	705,856	304,019	86,933	1,096,808
TRANSMISSION	(350) Land and Land Rights	125,899	8,437,339	11,983,897	1,103,385	21,650,520
TRANSMISSION	(352) Structures and Improvements	(76,874)	802,048	2,849,351	900,151	4,474,677
TRANSMISSION	(353) Station Equipment	8,482,356	35,159,439	55,136,701	19,455,487	118,233,984
TRANSMISSION	(354) Towers and Fixtures	-	89,944	357,051	186,913	633,908
TRANSMISSION	(355) Poles and Fixtures	6,649,823	11,344,264	36,197,044	17,840,232	72,031,362
TRANSMISSION	(356) Overhead Conductors and Devices	(188,022)	30,320,018	15,173,671	(16,932,098)	28,373,568
TRANSMISSION	(357) Underground Conduit	210,111	338,503	1,689,758	(280,602)	1,957,771
TRANSMISSION	(358) Underground Conductors and Devices	161,094	4,331,924	1,655,091	(660,669)	5,487,440
DISTRIBUTION	(360) Land and Land Rights	907,219	6,166,680	8,833,653	(1,051,368)	14,856,183
DISTRIBUTION	(361) Structures and Improvements	712,059	2,544,669	3,085,864	1,131,334	7,473,926
DISTRIBUTION	(362) Station Equipment	10,265,427	37,921,966	21,411,660	17,705,646	87,304,699
DISTRIBUTION	(364) Poles, Towers, and Fixtures	5,460,236	30,360,951	32,512,373	14,241,261	82,574,821
DISTRIBUTION	(365) Overhead Conductors and Devices	1,010,927	20,537,003	12,559,215	3,424,420	37,531,565
DISTRIBUTION	(366) Underground Conduit	4,357,128	21,507,740	26,134,008	11,268,227	63,267,102
DISTRIBUTION	(367) Underground Conductors and Devices	19,527,861	123,846,045	134,150,439	43,746,747	321,271,092
DISTRIBUTION	(368) Line Transformers	7,879,096	43,258,288	54,599,390	16,721,280	122,458,054
DISTRIBUTION	(369) Services	8,436,777	11,634,179	10,876,148	1,777,792	32,724,896
DISTRIBUTION	(370) Meters	3,511,866	17,715,395	23,761,745	9,690,474	54,679,480
DISTRIBUTION	(371) Installations on Customer Premises	360,691	2,077,790	3,605,972	1,145,037	7,189,490
DISTRIBUTION	(373) Street Lighting and Signal Systems	127,991	4,227,010	1,441,832	2,037,719	7,834,552
GENERAL & INTANGIBLE	(389) Land and Land Rights	0	-	103,202	(103,202)	0
GENERAL & INTANGIBLE	(390) Structures and Improvements	(1,147,713)	9,713,523	5,250,425	1,594,198	15,410,432
GENERAL & INTANGIBLE	(391) Office Furniture and Equipment	11,382,138	17,718,199	9,102,781	5,068,038	43,271,156
GENERAL & INTANGIBLE	(392) Transportation Equipment	306,450	2,710,628	2,723,379	423,431	6,163,889
GENERAL & INTANGIBLE	(393) Stores Equipment	-	1,726	-	-	1,726
GENERAL & INTANGIBLE	(394) Tools, Shop and Garage Equipment	690,570	2,293,832	2,632,102	1,153,814	6,770,318
GENERAL & INTANGIBLE	(395) Laboratory Equipment	1,327	130,588	149,187	-	281,102
GENERAL & INTANGIBLE	(396) Power Operated Equipment	73,826	185,183	125,253	970,075	1,354,337
GENERAL & INTANGIBLE	(397) Communication Equipment	2,618,154	9,845,387	13,842,254	4,816,731	31,122,526
GENERAL & INTANGIBLE	(398) Miscellaneous Equipment	167,096	5,238,162	(138,373)	370,258	5,637,143
		201,849,247	574,458,275	639,143,224	309,578,078	1,725,028,824

ARIZONA PUBLIC SERVICE COMPANY
Total Additions Between January 2008 and May 2008

Account	Additions
(301) Organization	0
(302) Franchises and Consents	0
(303) Miscellaneous Intangible Plant	13,944,629
(310) Land and Land Rights	0
(311) Structures and Improvements	1,101,008
(312) Boiler Plant Equipment	43,885,621
(313) Engines and Engine-Driven Generators	0
(314) Turbogenerator Units	6,415,648
(315) Accessory Electric Equipment	3,030,608
(316) Misc. Power Plant Equipment	947,997
(317) Asset Retirement Costs for Steam Production	0
(320) Land and Land Rights	0
(321) Structures and Improvements	1,742,330
(322) Reactor Plant Equipment	76,198,800
(323) Turbogenerator Units	18,502,834
(324) Accessory Electric Equipment	2,042,367
(325) Misc. Power Plant Equipment	302,042
(326) Asset Retirement Costs for Nuclear Production	(22,821,144)
(330) Land and Land Rights	0
(331) Structures and Improvements	0
(332) Reservoirs, Dams, and Waterways	0
(333) Water Wheels, Turbines, and Generators	0
(334) Accessory Electric Equipment	0
(335) Misc. Power Plant Equipment	0
(336) Roads, Railroads, and Bridges	0
(337) Asset Retirement Costs for Hydraulic Production	0
(340) Land and Land Rights	0
(341) Structures and Improvements	665,366
(342) Fuel Holders, Products, and Accessories	521,318
(343) Prime Movers	64,196
(344) Generators	5,138,160
(345) Accessory Electric Equipment	64,654
(346) Misc. Power Plant Equipment	86,933
(350) Land and Land Rights	1,103,385
(352) Structures and Improvements	900,151
(353) Station Equipment	19,455,487
(354) Towers and Fixtures	186,913
(355) Poles and Fixtures	17,840,232
(356) Overhead Conductors and Devices	(16,932,098)
(357) Underground Conduit	(280,602)
(358) Underground Conductors and Devices	(660,669)
(360) Land and Land Rights	(1,051,368)
(361) Structures and Improvements	1,131,334
(362) Station Equipment	17,705,646
(363) Storage Battery Equipment	0
(364) Poles, Towers, and Fixtures	14,241,261
(365) Overhead Conductors and Devices	3,424,420
(366) Underground Conduit	11,268,227
(367) Underground Conductors and Devices	43,746,747
(368) Line Transformers	16,721,280
(369) Services	1,777,792
(370) Meters	9,690,474
(371) Installations on Customer Premises	1,145,037
(372) Leased Property on Customer Premises	0
(373) Street Lighting and Signal Systems	2,037,719
(389) Land and Land Rights	(103,202)
(390) Structures and Improvements	1,594,198
(391) Office Furniture and Equipment	5,068,038
(392) Transportation Equipment	423,431
(393) Stores Equipment	0
(394) Tools, Shop and Garage Equipment	1,153,814
(395) Laboratory Equipment	0
(396) Power Operated Equipment	970,075
(397) Communication Equipment	4,816,731
(398) Miscellaneous Equipment	370,258
Total Additions between Jan08 and May08	309,578,076

ARIZONA PUBLIC SERVICE COMPANY
Total Additions Between January 2007 and December 2007

Account	Additions
(301) Organization	0
(302) Franchises and Consents	43,181
(303) Miscellaneous Intangible Plant	47,075,336
(310) Land and Land Rights	0
(311) Structures and Improvements	3,155,009
(312) Boiler Plant Equipment	50,682,418
(313) Engines and Engine-Driven Generators	0
(314) Turbogenerator Units	7,855,897
(315) Accessory Electric Equipment	4,496,952
(316) Misc. Power Plant Equipment	3,224,624
(317) Asset Retirement Costs for Steam Production	0
(320) Land and Land Rights	0
(321) Structures and Improvements	3,616,948
(322) Reactor Plant Equipment	3,503,210
(323) Turbogenerator Units	1,107,849
(324) Accessory Electric Equipment	291,094
(325) Misc. Power Plant Equipment	553,898
(326) Asset Retirement Costs for Nuclear Production	0
(330) Land and Land Rights	0
(331) Structures and Improvements	0
(332) Reservoirs, Dams, and Waterways	0
(333) Water Wheels, Turbines, and Generators	0
(334) Accessory Electric Equipment	0
(335) Misc. Power Plant Equipment.	0
(336) Roads, Railroads, and Bridges	0
(337) Asset Retirement Costs for Hydraulic Production	(3,908,222)
(340) Land and Land Rights	0
(341) Structures and Improvements	937,327
(342) Fuel Holders, Products, and Accessories	3,825,125
(343) Prime Movers	4,306
(344) Generators	16,676,357
(345) Accessory Electric Equipment	3,892,823
(346) Misc. Power Plant Equipment	304,019
(347) Asset Retirement Costs for Other Production	0
(350) Land and Land Rights	11,983,897
(352) Structures and Improvements	2,849,351
(353) Station Equipment	55,136,701
(354) Towers and Fixtures	357,051
(355) Poles and Fixtures	36,197,044
(356) Overhead Conductors and Devices	15,173,671
(357) Underground Conduit	1,689,758
(358) Underground Conductors and Devices	1,655,091
(360) Land and Land Rights	8,833,653
(361) Structures and Improvements	3,085,864
(362) Station Equipment	21,411,660
(363) Storage Battery Equipment	0
(364) Poles, Towers, and Fixtures	32,512,373
(365) Overhead Conductors and Devices	12,559,215
(366) Underground Conduit	26,134,008
(367) Underground Conductors and Devices	134,150,439
(368) Line Transformers	54,599,390
(369) Services	10,876,148
(370) Meters	23,761,745
(371) Installations on Customer Premises	3,605,972
(372) Leased Property on Customer Premises	0
(373) Street Lighting and Signal Systems	1,441,832
(374) Asset Retirement Costs Distribution Plant	0
(389) Land and Land Rights	103,202
(390) Structures and Improvements	5,250,425
(391) Office Furniture and Equipment	9,102,781
(392) Transportation Equipment	2,723,379
(393) Stores Equipment	0
(394) Tools, Shop and Garage Equipment	2,632,102
(395) Laboratory Equipment	149,187
(396) Power Operated Equipment	125,253
(397) Communication Equipment	13,842,254
(398) Miscellaneous Equipment	(138,373)
Total Additions between Jan07 and Dec07	**639,143,219**

ARIZONA PUBLIC SERVICE COMPANY
Total Additions Between January 2006 and December 2006

Account	Additions
(301) Organization	0
(302) Franchises and Consents	524,292
(303) Miscellaneous Intangible Plant	31,446,232
(310) Land and Land Rights	0
(311) Structures and Improvements	4,925,254
(312) Boiler Plant Equipment	15,171,714
(313) Engines and Engine-Driven Generators	0
(314) Turbogenerator Units	11,587,183
(315) Accessory Electric Equipment	5,577,757
(316) Misc. Power Plant Equipment	5,026,402
(317) Asset Retirement Costs for Steam Production	0
(320) Land and Land Rights	(414)
(321) Structures and Improvements	13,886,164
(322) Reactor Plant Equipment	8,102,499
(323) Turbogenerator Units	2,826,570
(324) Accessory Electric Equipment	835,332
(325) Misc. Power Plant Equipment	1,336,614
(326) Asset Retirement Costs for Nuclear Production	(17,956,065)
(330) Land and Land Rights	0
(331) Structures and Improvements	0
(332) Reservoirs, Dams, and Waterways	0
(333) Water Wheels, Turbines, and Generators	0
(334) Accessory Electric Equipment	0
(335) Misc. Power Plant Equipment	0
(336) Roads, Railroads, and Bridges	0
(337) Asset Retirement Costs for Hydraulic Production	0
(340) Land and Land Rights	(1,406)
(341) Structures and Improvements	2,267,221
(342) Fuel Holders, Products, and Accessories	(102,237)
(343) Prime Movers	(228,097)
(344) Generators	26,327,517
(345) Accessory Electric Equipment	1,741,462
(346) Misc. Power Plant Equipment	705,856
(347) Asset Retirement Costs for Other Production	0
(350) Land and Land Rights	8,437,339
(352) Structures and Improvements	802,048
(353) Station Equipment	35,159,439
(354) Towers and Fixtures	89,944
(355) Poles and Fixtures	11,344,264
(356) Overhead Conductors and Devices	30,320,018
(357) Underground Conduit	338,503
(358) Underground Conductors and Devices	4,331,924
(359) Roads and Trails	0
(359.1) Asset Retirement Costs for Transmission Plant	0
(360) Land and Land Rights	6,166,680
(361) Structures and Improvements	2,544,669
(362) Station Equipment	37,921,966
(363) Storage Battery Equipment	0
(364) Poles, Towers, and Fixtures	30,360,951
(365) Overhead Conductors and Devices	20,537,003
(366) Underground Conduit	21,507,740
(367) Underground Conductors and Devices	123,846,045
(368) Line Transformers	43,258,288
(369) Services	11,634,179
(370) Meters	17,715,395
(371) Installations on Customer Premises	2,077,790
(372) Leased Property on Customer Premises	0
(373) Street Lighting and Signal Systems	4,227,010
(374) Asset Retirement Costs Distribution Plant	0
(389) Land and Land Rights	0
(390) Structures and Improvements	9,713,523
(391) Office Furniture and Equipment	17,718,199
(392) Transportation Equipment	2,710,628
(393) Stores Equipment	1,726
(394) Tools, Shop and Garage Equipment	2,293,832
(395) Laboratory Equipment	130,588
(396) Power Operated Equipment	185,183
(397) Communication Equipment	9,845,387
(398) Miscellaneous Equipment	5,238,162
Total Additions between Jan06 and Dec06	**574,458,275**

ARIZONA PUBLIC SERVICE COMPANY
Total Additions Between Oct 2005 and December 2005

Account	Additions
(301) Organization	0
(302) Franchises and Consents	105,618
(303) Miscellaneous Intangible Plant	16,081,671
(310) Land and Land Rights	0
(311) Structures and Improvements	148,332
(312) Boiler Plant Equipment	2,965,180
(313) Engines and Engine-Driven Generators	0
(314) Turbogenerator Units	91,798
(315) Accessory Electric Equipment	686,204
(316) Misc. Power Plant Equipment	6,170
(317) Asset Retirement Costs for Steam Production	0
(320) Land and Land Rights	0
(321) Structures and Improvements	1,298,099
(322) Reactor Plant Equipment	69,993,552
(323) Turbogenerator Units	11,376,868
(324) Accessory Electric Equipment	(20,549)
(325) Misc. Power Plant Equipment	449,749
(326) Asset Retirement Costs for Nuclear Production	6,237,030
(330) Land and Land Rights	0
(331) Structures and Improvements	0
(332) Reservoirs, Dams, and Waterways	0
(333) Water Wheels, Turbines, and Generators	0
(334) Accessory Electric Equipment	0
(335) Misc. Power Plant Equipment	0
(336) Roads, Railroads, and Bridges	0
(337) Asset Retirement Costs for Hydraulic Production	0
(340) Land and Land Rights	0
(341) Structures and Improvements	764,874
(342) Fuel Holders, Products, and Accessories	71,693
(343) Prime Movers	172,906
(344) Generators	(221,275)
(345) Accessory Electric Equipment	(372,185)
(346) Misc. Power Plant Equipment	0
(347) Asset Retirement Costs for Other Production	0
(350) Land and Land Rights	125,899
(352) Structures and Improvements	(76,874)
(353) Station Equipment	8,482,356
(354) Towers and Fixtures	0
(355) Poles and Fixtures	6,649,823
(356) Overhead Conductors and Devices	(188,022)
(357) Underground Conduit	210,111
(358) Underground Conductors and Devices	161,094
(359) Roads and Trails	0
(359.1) Asset Retirement Costs for Transmission Plant	0
(360) Land and Land Rights	907,219
(361) Structures and Improvements	712,059
(362) Station Equipment	10,265,427
(363) Storage Battery Equipment	0
(364) Poles, Towers, and Fixtures	5,460,236
(365) Overhead Conductors and Devices	1,010,927
(366) Underground Conduit	4,357,128
(367) Underground Conductors and Devices	19,527,861
(368) Line Transformers	7,879,096
(369) Services	8,436,777
(370) Meters	3,511,866
(371) Installations on Customer Premises	360,691
(372) Leased Property on Customer Premises	0
(373) Street Lighting and Signal Systems	127,991
(374) Asset Retirement Costs Distribution Plant	0
(389) Land and Land Rights	0
(390) Structures and Improvements	(1,147,713)
(391) Office Furniture and Equipment	11,382,138
(392) Transportation Equipment	306,450
(393) Stores Equipment	0
(394) Tools, Shop and Garage Equipment	690,570
(395) Laboratory Equipment	1,327
(396) Power Operated Equipment	73,826
(397) Communication Equipment	2,618,154
(398) Miscellaneous Equipment	167,096
	201,849,247

ARIZONA CORPORATION COMMISSION
STAFF'S SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
JULY 31, 2008

Staff Interim 2.50 Provide an exhibit showing APS's bond ratings over the last 5 years from the various rating agencies. For each year that there is a change, either up or down, provide a detailed explanation of why that change occurred.

Response: See the attached exhibit, bates labeled APS13014, which shows APS's long-term debt ratings from 2004 to the present, along with the dates on which any of the ratings changed. Also attached is each of the applicable ratings downgrade articles, which provide a detailed explanation of why the change occurred. The following three articles are attached:

1. Standard and Poor's Rating Direct article from December 21, 2005 "Research Update: Pinnacle West Capital's, Arizona Public Service's Ratings Lowered To 'BBB-'; Outlook Stable" – APS13011

2. Fitch Ratings article from January 30, 2006 "Fitch Lowers PNW's and APS' Sr. Unsecured Ratings to 'BBB-' & 'BBB', Respectively; Outlook Stable" – APS13012

3. Moody's Investor Service article from April 27, 2006 "Moody's Downgrades Pinnacle West (Issuer Rating to Baa3) and Arizona Public Service (Sr.UNS. to Baa2); Ratings of Pinnacle West Remain Under Review – APS13013

Witness: Donald Brandt

APS Senior Unsecured Ratings History

APS	Current	12/31/2007	12/31/2006	12/31/2005	12/31/2004
Moody's	Baa2	Baa2	Baa2	Baa1	Baa1
S&P	BBB-	BBB-	BBB-	BBB-	BBB
Fitch	BBB	BBB	BBB	BBB+	BBB+

Moody's downgrade on April 27, 2006
S&P downgrade on December 21, 2005
Fitch downgrade on January 30, 2006

ARIZONA CORPORATION COMMISSION
STAFFS SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172 – INTERIM RATES
JULY 31, 2008

Staff Interim 2.38 Provide a description of all provisions in all APS bond indentures that address minimum financial ratios and/or default conditions.

Response: There are no provisions in any of APS's indentures that address minimum financial ratios. Some events of default are:

- Non-payment of principal, interest or fees;
- Non-compliance with covenants;
- Bankruptcy and insolvency events.

For a more complete list of events of default and their descriptions, please see the attached document, APS13344.

Witness: Donald Brandt

ARIZONA CORPORATION COMMISSION
STAFFS SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
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E-01345A-08-0172 – INTERIM RATES
JULY 31, 2008

Staff Interim 2.39 Provide a description of all provisions in all APS credit arrangements that address minimum financial ratios and/or default conditions.

Response: There are two provisions in APS's credit arrangements that address minimum financial ratios. The first one is the requirement that APS maintain an Interest Coverage of at least two times, and the second one requires that the amount of debt does not exceed 65% of total capitalization.

Some events of default are:

- Non-payment of principal, interest or fees;
- Material misrepresentations;
- Non-compliance with covenants;
- Non-payment under significant operating leases;
- Bankruptcy and insolvency events;
- Judgments against APS significantly exceeding insurance coverage;
- Change in control of PWCC or APS;
- ERISA violations.

For a more complete list of events of default and their descriptions, please see attached credit agreements:

1. $400 Million APS Revolving Credit Facility – APS13031
2. $500 Million APS Revolving Credit Facility – APS13032
3. 2005 Amendment to Coconino 1997 A Reimbursement Agreement – APS13033
4. Coconino 1994 Series A Reimbursement Agreement – APS13034
5. 2005 Amendment to Coconino 1998 A Reimbursement Agreement – APS13035
6. Coconino 1998 Series A Reimbursement Agreement – APS13036
7. Farmington Reimbursement Agreement – APS13037
8. Emerson S-L Reimbursement Agreement – APS13038
9. SecPac S-L Reimbursement Agreement – APS13039

Witness: Donald Brandt

ARIZONA CORPORATION COMMISSION
STAFF'S FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
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E-01345A-08-0172
JUNE 24, 2008

Staff 1.13: Briefly provide the purpose of the existing 2007 PSA surcharge?

Response:

In Decision No. 69663, the Commission permitted the 2007 PSA Adjustor to continue until it had collected a $46 million balance of uncollected fuel and purchased power costs. APS expects that the 2007 PSA Adjustor will have collected that historical balance at the end of the July billing cycle.

In its Motion, APS does not seek to continue the PSA Adjustor beyond its intended expiration. Rather, APS seeks approval of an entirely new Interim Base Rate Surcharge of the same amount. The new Interim Base Rate Surcharge, as explained in the Company's Motion, would not be devoted to the collection of fuel and purchased power costs (as was the 2007 PSA Adjustor), but would instead be used to ameliorate the detrimental impact of the Company's rising non-fuel costs until the Commission has the opportunity to enter an order on the Company's permanent rate request in the underlying general rate case.

STANDARD & POOR'S | RATINGSDIRECT

RESEARCH

Credit FAQ: Credit Issues Expected To Continue For Pinnacle West Capital Corp. And Arizona Public Service Co.

Publication date: 24-Jan-2006
Primary Credit Analyst: Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

On Dec. 21, 2005, Standard & Poor's Ratings Services lowered the corporate credit ratings on Arizona Public Service Co. (APS) and its parent, Pinnacle West Capital Corp. (PWCC) by one notch to 'BBB-'. This action reflected three factors: growing fuel and purchased power deferrals, which are weakening financial performance in 2005 and 2006, the lack of action by the Arizona Corporation Commission (ACC) in 2005 to address a portion of these deferrals through a special surcharge, and the likelihood of delays in the completion of APS' recent general rate case (GRC) filing, which suggest that financial weakening may extend into 2007.

Standard & Poor's stated at the time that any adverse regulatory developments or continued delays in resolving the pending surcharge request could trigger another rating action, which could include a revision of the stable rating outlook to negative, placing the company's debt rating on CreditWatch with negative implications, or lowering the rating to non-investment grade.

Frequently Asked Questions

How large are APS' deferrals of fuel and purchased power?

At Jan. 31, 2006, APS' estimated fuel and purchased power deferrals are expected to be about $165 million. These deferrals are accumulating because APS' base electric rates are set to reflect 2003 costs, and power and natural gas costs have far exceeded these rates. APS collects 2.0473 cents per kilowatt-hour (kWh) in rates for these costs, but for the 12 months ended September 2005, its actual cost averaged 2.701 cents per kWh. Because these rates will not be updated until the completion of APS' recently filed GRC or the emergency interim request, deferrals will likely continue to accumulate in 2006 and into 2007.

The amount by which 2006 actual fuel and purchased power costs will exceed the authorized expenditures will be a function of retail sales growth, commodity costs, the operational performance of APS' generation assets, and the fuel-in-base factor. Standard & Poor's has estimated that, at year-end 2006, the utility will likely incur an additional $250 million in fuel and purchased power costs that are not recoverable in base electric rates. The sum of balances to date of $165 million plus the expected incremental deferrals of $250 million total $415 million; however, because APS has the potential to collect some of its 2005 balances through a power supply adjuster (PSA) beginning April 1, year-end 2006 deferrals on the utility's balance sheet will not reach that level.

What are the ways that APS could recover its expected deferrals?

Under the terms of a settlement reached in APS' 2003 rate case approved by the ACC in April 2005, the PSA may be increased as much as four mills per kWh (a cap over the life of the PSA) on April 1, 2006. Using 2005 retail sales, and assuming a 4.5% growth rate (which is consistent with recent results), the four mills should yield about $125 million in rate relief on an annualized basis, or about $83 million for the eight months of 2006. Thus, as a rough approximation, APS' deferred balance would be about $330 million at year-end 2006.

On Jan. 17, the chairman of the ACC introduced a proposal to accelerate the PSA adjustment to Feb. 1. If this were approved by the ACC, an additional two months of the PSA would provide about $20 million in incremental revenues (e.g., roughly $125 million multiplied by two-twelfths of the year) in 2006. Thus, if the Hatch-Miller amendment moves forward, year-end 2006 deferred balances will be closer to about $310 million. The amendment is expected to be discussed on Jan. 24.

APS06982

Additional relief could be provided if the ACC grants APS' request to recover $80 million by means of a two-year special surcharge that would increase retail rates by about 2%. On Jan. 4, an administrative law judge issued a decision indicating that APS' surcharge application is premature until the company's first power supply adjustment occurs in April. An ACC vote is scheduled for Jan. 24. Standard & Poor's current assumption is that the surcharge will be approved by the ACC, but will be delayed until July 1, 2006. A surcharge implemented at this time would provide roughly an additional $20 million to the company in 2006. If it were implemented sooner, the impact on deferrals would be relatively small, providing about $3 million in each month it is in place during 2006. If the Hatch-Miller amendment were approved and a surcharge was implemented and approved for Feb. 1, the two measures collectively would bring between $50 million-$57 million in relief. Accordingly, relative to the year-end expected balances, an accelerated surcharge and PSA, if granted, will reduce deferrals but only by about 20% in the best-case scenario.

What is the status with APS' emergency interim filing?
On Jan. 6, 2006, APS filed a $299 million request for emergency fuel and purchased power-related rate relief. Any amounts, if granted, would be subject to future prudency review. As part of a procedural conference on Jan. 12, four of the five commissioners questioned the definition an emergency and whether relief is justified. Based on the strong views expressed, it appears unlikely that the filing has support. On Jan. 19, a procedural schedule was set that should allow for a decision in April 2006. Standard & Poor's forecast estimates do not assume emergency relief is granted.

Are there credit concerns related to APS' rate cap?
Balancing these potential sources of rate relief are additional adverse financial effects that could occur for APS if its "hard cap" of $776 million is not lifted. The cap is part of APS' 2004 settlement, approved by the ACC in April 2005, which restricts the total amount of annual fuel and purchased power costs that can be collected in retail rates. APS expects that its fuel and purchased power costs will exceed the cap in the fourth quarter of 2006, and has indicated publicly that its estimated fuel costs will exceed $800 million. As part of its emergency interim filing, APS has requested that the cap be removed. If the cap is not lifted, any amounts above $776 million would be unrecoverable, putting further pressure on cash flows.

What assumptions does Standard & Poor's make about the performance of APS' generation assets in estimating deferred balances?
Standard & Poor's estimates assume normal operational performance of APS' generation fleet. Forced outages could increase deferred balances. Palo Verde unit 1 is in the process of exiting an outage that occurred last week due to pipe vibrations within the emergency cooling system. APS took the unit offline last week to install clamps in an effort to stop the excess vibrations. From late December until Jan. 17, unit 1 has operated at about 30% capacity while crews have tried to fix the problem, which followed the completion of the unit's exit from a refueling and maintenance outage begun in the fall of 2005. The plant is expected to maintain approximately this level of reduced capacity while additional repairs are considered. Replacement power costs have been incurred in association with this last outage, and could build, depending on the timeline for a solution to be implemented. These and any future costs are not part of Standard & Poor's deferred estimates.

How are these estimated deferrals expected to affect 2005 and 2006 financial performance, especially in the context of the credit benchmarks at the 'BBB-' rating?
Year-end results for 2005 are not yet available, but Standard & Poor's expects that 2005 and 2006 results will be on par with the 12 months ending Sept. 30, 2005, when consolidated adjusted funds from operations (FFO) to total debt was 14.8%. FFO to total debt is an important metric for Standard & Poor's, and at a business profile of '6' (on a 10-point scale where '1' is excellent and '10' vulnerable), it reflects a below-investment-grade performance. For the 12 months ending Sept. 30, 2005, FFO interest coverage was 3.3x, which is reasonable for the current rating. Adjusted total debt to total capitalization was 53.1%, and is solid for the current rating.

Performance in 2007 will be heavily dependent on when the GRC is resolved. APS filed on Nov. 4, 2005, for a $409.1 million (or 19.9%) rate increase, the majority of which is related to fuel and purchased power costs. Typically, the ACC certifies the application as complete within 30 days, and the case commences. But in early December 2005, the ACC requested that the company re-file its application using a test year ending Sept. 30, 2005, rather than the Dec. 31, 2004 data that APS used. The updated application is expected to be re-submitted to the ACC on Jan. 31, 2005.

As a result, the case will not begin until early March 2006, suggesting that an outcome will be delayed roughly three months from the original schedule, which envisions a ruling by early 2007. Recent public statements by the ACC indicate that spring 2007 may be the earliest a decision could be expected. But there is little precedent in Arizona that would suggest a year-long rate case is likely. A more conservative estimate would assume mid-2007. This could be a credit concern because if permanent rate relief is not in place prior to the peak summer season, financial recovery could also be stalled in 2007.

How is the company's liquidity?

Unaudited consolidated cash and investments stood at roughly $150 million as of Dec. 31, 2005. PWCC and APS also maintain a total of $700 million in revolving credit facilities, which had approximately $15 million of usage at year-end 2005 for miscellaneous letters of credit. Standard & Poor's preliminary assessment is that the company's credit lines should be sufficient to support working capital needs, purchases of gas and power, as well as fund margining and collateral requirements for trading operations. As of Dec. 31, 2005, PWCC and APS comfortably met their loan covenant requirements.

PWCC has a $300 million dollar maturity on April 1, which it plans to refinance. Adverse regulatory actions could affect the costs of borrowing or even access to the capital markets, although this is not currently seen as a significant threat.

APS' reliance on purchases and gas-fired peaking capacity during the winter is low; however, this is seasonal. Fuel and purchased power expenses are anticipated to be accrued faster in July 2006 through September 2006. Standard & Poor's is conducting a more detailed liquidity assessment, which will be completed once more clarity is provided on how the ACC is expected to address interim rate relief requests. APS has a significant hedging program and 85% of its 2006 power and gas requirements are hedged. APS and PWCC are currently holding counterparties' collateral as a result of their in-the-money hedged positions.

Could cost saving measures, or the sale of nonregulated assets by PWCC assist in restoring credit quality?

The ACC has requested that the company explain what cost reductions it is making to compensate for the fact that its retail rates are not aligned with production costs. In response, the company cancelled bonuses for its corporate officers, and is certain to investigate additional cost-savings measures. While these actions may address other public policy issues of concern to the ACC, from a credit standpoint cost cutting measures are unlikely to materially alleviate APS' sagging financial performance.

The deferred balances stem from fuel and purchased power costs that the utility incurred to serve retail loads. APS earns no margin on these expenses; they are simply passed straight through to customers. Similar to the circumstances that other western utilities have faced in recent years, APS' fuel and purchased costs substantially exceed the amount currently recoverable in rates. The company may be able to temporarily subsidize the cost of serving retail loads by reducing expenses in other parts of the company, selling other PWCC assets, or issuing debt, but such a strategy is not sustainable, and could very well result in longer-term adverse consequences for the company.

STANDARD & POOR'S

RATINGSDIRECT®

June 25, 2008

Summary:
Arizona Public Service Co.

Primary Credit Analyst:
Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

Table Of Contents

Summary:

Arizona Public Service Co.

Credit Rating: BBB-/Stable/A-3

Rationale

Standard & Poor's Ratings Services today affirmed the 'BBB-' corporate credit rating assigned to Pinnacle West Capital Corporation (PWCC) and its utility, Arizona Public Service. The outlook is stable. The consolidated credit ratings of PWCC primarily reflect the operations of its largest subsidiary, APS, a regulated, electric utility serving about 1.1 million customers within its service territory, which spans roughly two-thirds of Arizona and includes about half of the Phoenix MSA. We view the business profile of PWCC and APS to be 'strong'. While the company continues to benefit from a number of favorable attributes including a good service territory, a reasonably balanced power supply portfolio and a good PSA. However, APS' continues to face significant regulatory challenges.

APS provided the company with about 92% of its consolidated net income in 2007. SunCor, PWCC's real estate development company, provided about 4%, but due to the significant real estate slowdown in the southwest, it is unlikely it will be a meaningful contributor of cash flows or income over the next several years. (Prior to the real estate downturn, our forecasts have conservatively limited earnings from this subsidiary due to the cyclic nature of its cash flows.) Other subsidiary operations include Pinnacle West Trading and Marketing, which contributed about 4% of consolidated net income in 2007. This subsidiary has since last year been minimizing trading operations. Its largest contract was serving all-requirements load for UNS Electric Inc., which ended in May 2008.

We view the financial profile of PWCC and APS to be 'aggressive', which reflects: year-end debt to total capitalization of 57% (adjusted for items such as power purchases and operating leases); heavy capital spending that is expected to drive negative free operating cash flow for the foreseeable future; cash flow weakness as a function of protracted rate cases; and, while modest, the presence of unregulated activities, which can be unpredictable in their earnings contributions.

Because the preponderance of cash flows for consolidated operations stems from APS, we expect financial performance will continue to be heavily dependent on regulatory outcomes. The conclusion of APS' last general rate case in June 2007 (filed in November 2005 and revised in early 2006) provided the company with mechanisms to recover legacy deferrals and speed the recovery of fuel costs going forward. This rate relief, in place for the last half of 2007, assisted the company in maintaining credit metrics roughly in line with past performance. Funds from operations (FFO) to total debt was about 16% at year-end, with FFO interest coverage around 4x. On a trailing 12-month basis the company's performance has been slightly above these levels, due in part to the federal tax stimulus package approved by the U.S. Congress earlier this year, which is expected to increase deferred taxes (which are added back to FFO and thus increase this total).

We expect APS to be in more or less continuous rate case mode for the next few years. Given APS' capital spending program, forecasted to be about $1.1 billion annually through 2010, the utility will need to file regular general rate cases to manage recovery of its investment. The use of a historical test year in Arizona, coupled with the fact that fully litigated rate cases take between 18 to 24 months to complete, is expected to result in no meaningful improvement in financial performance through 2009 and possibly beyond, depending on the timing and the

outcome of the company's current case.

APS filed its current rate case in March 2008. ACC staff requested that the company revise its filing to reflect a test year ending Dec. 31, 2007 (as opposed to the originally filed version based on a Sept. 30, 2007, test year). The revised case has not been officially certified by the ACC, but certification is expected by July 2. Unlike the company's last rate case, in which $315 million of the $322 million of rate relief granted was for fuel and power-related costs, the majority of the current case is for nonfuel expenditures.

While the revised case increased the company's request to $278 million (about an 8.5% increase, excluding the company's request that customers be assessed about $53 million in impact fees), the re-filing means that is unlikely the ACC will reach an outcome in the case before October 2009, and because the majority of APS' sales occur in the summer months, the company's financial performance could weaken in 2009.

This month, the company requested that the ACC allow it to continue to collect a $0.004/kWh charge that it has been collecting in 2007 to recover legacy purchased power and fuel deferrals. Given that the portion of deferred costs associated with this surcharge is due to be paid by July or August, APS has asked that the ACC continue the charge, but authorize collection as an interim base rate increase, subject to refund as part of the resolution of its rate case, expected in fall 2009. (Last year, the ACC approved similar relief for Tucson Electric Power in its pending rate case settlement when it granted the southern Arizona utility the opportunity to continue to collect charges related to a competitive transition charge, or CTC, while its rate case is pending.) While retail customers would essentially see no rate increase because APS is asking to continue the surcharge as an interim increase, it is unclear what action the ACC will take. A vote could occur as early as late summer.

In 2008, we expect a procedural schedule to be established for the APS rate case, and greater clarity around the timing of an outcome will be available once this is issued. Of note is that three of the five commissioners are facing term limits and will no longer be on the ACC beginning in 2009. Commissioners are popularly elected and about a dozen candidates have announced they will run for the November election. As a result, a majority of the commissioners presiding now will not be on the commission when an APS rate case ruling is rendered. What this means for credit quality is unclear.

APS was successful earlier this year in receiving approval for a change in its line extension policies, which eliminates the free footage allowance that used to be available for customers. As a result, the portion of the company's capital expenditures associated with new line extensions will be offset with contributions in aid of construction (CIAC). This is favorable and year to date ended March 31, 2008, had added about $10 million in incremental cash flows to the company. Because it is booked under investing activities, cash flow metrics are not improved, but we recognize the significant benefit of APS receiving upfront cash from customers to meet a portion of its distribution capital investment plans. Future cash flows from customers in the form of CIAC will depend on the number of new meter sets, which are significantly off year to date due to the poor real estate market in Arizona and a slowing economy generally.

APS has a well-diversified power supply portfolio that in 2007 consisted of about 22% nuclear generation, 37% coal generation, approximately 18% owned gas generation, and the balance, about 23%, of purchases. We would expect the company's purchased power obligations to steadily climb due to the fact that APS is under a self build moratorium until 2015. APS will also need to meet relatively stringent renewable portfolio standards (RPS). It has in place a surcharge to pass through to customers the costs of RPS compliance.

Palo Verde performance has stabilized, and it has a plan in place to address NRC concerns. As of the first quarter of 2008, the combined capacity factors for all three Palo Verde units was 93%, as compared with 79% for 2007 (which reflects in part an extended planned outage to replace steam generators at unit 3) and 71% in 2006, which largely reflects unplanned outages at unit 1 related to excessive vibration that occurred when that unit exited its extended outage for refueling and replacement of steam generators. Palo Verde Unit 3 remains in the NRC's "multiple/repetitive degraded cornerstone" column of the NRC's Action matrix, which subjects all three Palo Verde units to enhanced NRC inspection regime. Preliminary work in support of this took place throughout the summer of 2007. In February, the NRC issued its inspection report, which determined the plant was operating safely but which also outlined an improvement plan for APS. In late March, APS in turn submitted to the NRC a final improvement plant addressing issues raised in the NRC inspection report. While the nuclear units appear to be on a path to improve operational performance and restore NRC confidence in the operational and safety standards at the plant, this will remain an area of concern until the NRC removes it degraded designation.

Short-term credit factors

APS and PWCC's short-term rating is 'A-3'. Liquidity is adequate. Pinnacle West has $18 million of cash and cash equivalents, and total credit facilities of nearly $1.4 billion, with approximately $943 million available as of March 31, 2008. In October 2007, APS received approval from ACC to increase its authorized short-term debt borrowing capacity by $500 million, and long-term debt borrowing capacity by $1 billion. This will help address the needs of its growing customer base, and the increasing requirement for natural gas and purchased power.

Pinnacle West had close to $185 million available under its $300 million unsecured revolving credit facility that expires in December 2010. APS had $682 million available under its two unsecured revolving credit facilities, $400 million of which expires in December 2010, and $500 million in September 2011. SunCor has two credit facilities expiring in October and December 2008 that total $170 million and approximately $76 million, respectively, available as of September 2007.

Discretionary cash flow is expected to be negative for 2008 due to APS' capital expenditure plans. Excluding the remarketing of APS' pollution control debt, neither PWCC nor APS has any significant debt obligations maturing until 2011.

Outlook

The stable outlook reflects our expectation that consolidated cash flow volatility has been tamped down by the ACC's approval of a stronger PSA that speeds the recovery of fuel costs, but consolidated financial performance will continue to be challenged by regulatory lag at APS, which could be moderated by APS' pending interim rate request. The stable outlook is premised on no meaningful adverse changes in the company's business risks and continued financial performance that is not significantly weaker than 2007 results. Equity issuances will be expected to balance the capital structure of the company as APS continues to invest heavily in infrastructure. Ratings could be lowered to speculative grade if the company is not able to overcome the challenge of ensuring timely recovery of its prudently incurred costs through rate increases approved by the ACC. Given these challenges, and that presented by NRC scrutiny of Palo Verde, we see little potential for positive movement in the ratings or outlook.

FitchRatings
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Fitch : Info Center : Press Releases

Fitch Lowers PNW & APS' Sr. Unsecured Ratings to 'BBB-' & 'BBB', Respectively; Outlook Stable

Ratings
30 Jan 2006 4:23 PM (EST)

Fitch Ratings-New York-30 January 2006: Fitch Ratings has lowered Pinnacle West Capital's (PNW) long- and short-term ratings. At the same time, Fitch has lowered Arizona Public Service Company's (APS) long-term ratings, while affirming its commercial paper rating. The securities of PNW and APS have been removed from Rating Watch Negative, where they were placed Jan. 6, 2006. The Rating Outlook is Stable. The following actions are effective immediately:

Pinnacle West Capital:

--Issuer default rating (IDR) downgraded to 'BBB-' from 'BBB';
--Senior unsecured debt downgraded to 'BBB-' from 'BBB';
--Commercial Paper downgraded to 'F3' from 'F2'.

The Rating Outlook is Stable.

Arizona Public Service Co.

--IDR downgraded to 'BBB-' from 'BBB';
--Senior unsecured debt downgraded to 'BBB' from 'BBB+';
--Commercial Paper affirmed at 'F2'.

The Rating Outlook is Stable.

Approximately $3.8 billion of debt is affected by the rating actions.

The rating actions and Stable Rating Outlook reflect the resolution of APS' power supply adjustor (PSA) proceedings by the Arizona Corporation Commission (ACC) and the utility's significant exposure to high and rising natural gas commodity costs. The commodity exposure is a function of a generating capacity mix, about half of which is natural gas fired, and rapid service territory load growth, which is likely to be met predominantly by natural gas-fired resources. The revised ratings also consider the operational risk and asset concentration of the Palo Verde nuclear plant. The facility has experienced intermittent operating problems over the past year and a sustained, unscheduled outage at the plant could lead to further negative rating actions.

The ACC decision in the PSA proceedings, issued on Jan. 25, 2006, has positive and negative implications for PNW and APS' creditworthiness. The commission's decision to accelerate the effective date of the PSA rate to Feb. 1 from April 1, along with the removal of the $776 million annual power supply cost limit, were constructive developments in Fitch's view. However, the ACC bench order rejecting APS's $80 million surcharge request on procedural grounds and restriction of PSA adjustments to an annual reset is less favorable than Fitch had anticipated in its previous ratings and is a significant source of concern for PNW and APS fixed-income investors. The fact that there is no vehicle within the PSA protocol to recover supply costs more frequently than annually during periods of sustained high and rising energy costs subjects APS to significant cash flow volatility and working capital requirements. Such costs would be exacerbated in a meaningful way by an extended outage of a base load nuclear- or coal-fired generating facility during periods of peak demand. The only option to recover fuel and purchase power costs above amounts determined annually in the PSA would be an emergency rate filing, in which the timing and amount of rate relief would be uncertain.

It is Fitch's understanding that energy cost deferrals in a particular year of up to four mills per kilowatt hour (approximately $110 million-$115 million on an annual run rate) will be recovered through an annual PSA rate adjustment that will recover those costs over the following 12 months. The surcharge is expected to facilitate recovery of costs in excess of the four mills per kilowatt hour limit over a time horizon to be determined by the commission.

Contact: Philip Smyth, CFA +1-212-908-0531 or Robert Hornick +1-212-908-0523, New York.

Media Relations: Brian Bertsch, New York, Tel: +1 212-908-0549.

Fitch's rating definitions and the terms of use of such ratings are available on the agency's public site, 'www.fitchratings.com'. Published ratings, criteria and methodologies are available from this site, at all times. Fitch's code of conduct, confidentiality, conflicts of interest, affiliate firewall, compliance and other relevant policies and procedures are also available from the 'Code of Conduct' section of this site.

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E-01345A-08-0172
JULY 31, 2008

Staff Interim 2.56 Provide all quantitative analysis that APS has concerning the amount of additional annual revenues it would take to raise its bond rating up by one step.

Response: APS has not prepared such quantitative analyses. The Company's interim rate request and general rate case request are both needed in order to maintain current ratings levels and would not, in and of themselves, raise its ratings by any degree.

Witness: Donald Brandt

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Staff Interim 2.55 Provide all quantitative analysis that APS has concerning the impact of bond ratings on cost of capital. Include all Excel files and supporting calculations.

Response: Attached as APS13015 is the impact of bond ratings on cost of capital. See also Donald E. Brandt's affidavit and response to 2.3.

Witness: Donald Brandt

	Bond Rating [1]	
	BBB	**Below Investment Grade**
1999	7.98%	9.44%
2000	7.55%	9.78%
2001	7.26%	8.95%
2002	6.44%	16.11%
2003	4.75%	7.56%
2004	4.87%	6.69%
2005	5.53%	6.88%
2006	5.87%	6.80%
2007	5.94%	8.15%

Difference between BBB and High Yield:

Nine Year Avg. (1999-2007)	2.68%
Eight Year Avg. (2000-2007)	2.84%
Seven Year Avg. (2001-2007)	2.92%
Six Year Avg. (2002-2007)	**3.13%**
Five Year Avg. (2003-2007)	1.82%
Four Year Avg. (2004-2007)	1.58%
Three Year Avg. (2005-2007)	**1.50%**
Two Year Avg. (2006-2007)	1.57%

Notes:
(1) Rates reflect year-end levels from the Lehman Brothers Utility Index - includes all publicly registered fixed rate deals greater than $250 million, with an initial maturity greater than 18 months, and more than 12 months remaining until maturity

Low Spread

ARIZONA PUBLIC SERVICE COMPANY
Additional Interest Costs at Non-Investment Grade
($000)

YEAR	SECURITY	CREDIT	FACE VALUE	CURRENT RATE/FEE	BIG RATE/FEE	COST DIFFERENTIAL	ADDITIONAL ANNUAL INTEREST	CUMULATIVE ADDITIONAL INTEREST
	Short-Term Debt:							
2010	CP/Revolver		400,000	0.500%	0.850%	1,400		
	Unused Revolver:							
2010	Revolver $400m		400,000	0.110%	0.175%	260		
2010	Revolver $500m		73,290	0.100%	0.175%	55		
	Unused Revolver Subtotal		473,290			315		
	Tax-Exempt No Enhancement:							
2010	Coc 1996A & 1999		26,710	3.530%	4.845%	351		
	Auction Rate Tax-Exempt Insured:							
2010	Coc 2004A		12,850	0.325%	0.550%	29		
2010	Nav 2004A-E		166,150	0.325%	0.550%	374		
2010	Mar 2005A-E		163,975	0.265%	0.415%	246		
	Auction Rate Tax-Exempt Insured Subtotal		**342,975**			**649**		
	Tax-Exempt w/ L/C:							
2010	Farm 1994A-C		146,650	0.600%	1.000%	587		
2010	Coc 1994A & 1998		49,520	0.700%	1.200%	248		
	Tax-Exempt w/ L/C Subtotal		**196,170**			**834**		
	New(N)/Refinanced(R) LT Debt:							
2010	Sr. Note (N)		250,000	0.000%	1.495%	3,738	7,287	7,287
2011	6.375% Sr. Note (R)		400,000	0.000%	1.495%	5,981	0	0
2011	Sr. Note (N)		550,000	0.000%	1.495%	8,224	21,493	28,781
2012	6.5% Sr. Note (R)		375,000	0.000%	1.495%	5,608	0	0
2012	Sr. Note (N)		50,000	0.000%	1.495%	748	27,848	56,629
2013	Mar 2002A (R)		90,000	0.450%	0.600%	135	0	0
2013	Sr. Note (N)		250,000	0.000%	1.495%	3,738	31,722	88,350
2014	5.8% Sr. Note (R)		300,000	0.000%	1.495%	4,486	0	0
2014	Sr. Note (N)		250,000	0.000%	1.495%	3,738	39,946	128,296
2015	4.65% Sr. Note (R)		300,000	0.000%	1.495%	4,486	0	0
2015	Sr. Note (N)		550,000	0.000%	1.495%	8,224	52,656	180,953
2016	6.25% Sr. Note (R)		250,000	0.000%	1.495%	3,738	0	0
2016	Sr. Note (N)		250,000	0.000%	1.495%	3,738	60,133	241,086
2017	Sr. Note (N)		250,000	0.000%	1.495%	3,738	63,871	304,957
2018	Sr. Note (N)		250,000	0.000%	1.495%	3,738	67,610	372,567
2019	Sr. Note (N)		250,000	0.000%	1.495%	3,738	71,348	443,914

High Spread

ARIZONA PUBLIC SERVICE COMPANY
Additional Interest Costs at Non-Investment Grade
($000)

YEAR	SECURITY	CREDIT	FACE VALUE	CURRENT RATE/FEE	BIG RATE/FEE	COST DIFFERENTIAL	ADDITIONAL ANNUAL INTEREST	CUMULATIVE ADDITIONAL INTEREST
	Short-Term Debt:							
2010	CP/Revolver		400,000	0.500%	0.850%	1,400		
	Unused Revolver:							
2010	Revolver $400m		400,000	0.110%	0.175%	260		
2010	Revolver $500m		73,290	0.100%	0.175%	55		
	Unused Revolver Subtotal					**315**		
	Tax-Exempt No Enhancement:							
2010	Coc 1996A & 1999		26,710	3.530%	4.845%	351		
	Auction Rate Tax-Exempt Insured:							
2010	Coc 2004A		12,850	0.325%	0.550%	29		
2010	Nav 2004A-E		166,150	0.325%	0.550%	374		
2010	Mar 2005A-E		163,975	0.265%	0.415%	246		
	Auction Rate Tax-Exempt Insured Subtotal		**342,975**			**649**		
	Tax-Exempt w/ L/C:							
2010	Farm 1994A-C		146,650	0.600%	1.000%	587		
2010	Coc 1994A & 1998		49,520	0.700%	1.200%	248		
	Tax-Exempt w/ L/C Subtotal		**196,170**			**834**		
	New(N)/Refinanced(R) LT Debt:							
2010	Sr. Note (N)		250,000	0.000%	3.131%	7,827	11,376	11,376
2011	6.375% Sr. Note (R)		400,000	0.000%	3.131%	12,523	0	0
2011	Sr. Note (N)		550,000	0.000%	3.131%	17,219	41,117	52,493
2012	6.5% Sr. Note (R)		375,000	0.000%	3.131%	11,740	0	0
2012	Sr. Note (N)		50,000	0.000%	3.131%	1,565	54,422	106,915
2013	Mar 2002A (R)		90,000	0.450%	0.600%	135	0	0
2013	Sr. Note (N)		250,000	0.000%	3.131%	7,827	62,384	169,299
2014	5.8% Sr. Note (R)		300,000	0.000%	3.131%	9,392	0	0
2014	Sr. Note (N)		250,000	0.000%	3.131%	7,827	79,603	248,902
2015	4.65% Sr. Note (R)		300,000	0.000%	3.131%	9,392	0	0
2015	Sr. Note (N)		550,000	0.000%	3.131%	17,219	106,213	355,116
2016	6.25% Sr. Note (R)		250,000	0.000%	3.131%	7,827	0	0
2016	Sr. Note (N)		250,000	0.000%	3.131%	7,827	121,867	476,982
2017	Sr. Note (N)		250,000	0.000%	3.131%	7,827	129,693	606,676
2018	Sr. Note (N)		250,000	0.000%	3.131%	7,827	137,520	744,196
2019	Sr. Note (N)		250,000	0.000%	3.131%	7,827	145,347	889,543

ARIZONA CORPORATION COMMISSION
STAFF'S SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
JULY 31, 2008

Staff Interim 2.71 (a) Please identify all current long-term debt APS has that was issued when APS had a bond rating of BBB-. (b) Please provide APS's best estimate of the cost of each debt issuance identified in response to part a, if APS had instead at the time of issuance had a bond rating of BBB. Include all Excel files and supporting calculations.

Response: (a) APS has issued $400 million of long-term debt since S&P downgraded it to BBB- on December 21, 2005. This debt was issued on 8/3/2006 in two tranches, $250 million maturing on 8/1/2016 with a coupon of 6.25% and $150 million maturing on 8/1/2036 with a coupon of 6.875%.

(b) If APS had had a bond rating of BBB at the time the amount referred to in subpart (a) was issued the coupon on these two tranches would have been approximately 6.20% and 6.825% respectively. This would have resulted in interest expense savings of $1.25 million and $2.25 million over the life of the bonds.

Witness: Donald Brandt

ARIZONA CORPORATION COMMISSION
STAFF'S SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172 – INTERIM RATES
JULY 31, 2008

Staff Interim 2.27 Refer to paragraphs 33 and 35, of Mr. Brandt's 6/6/08 affidavit. (a) Given the current rate case schedule, when does APS anticipate that base rates being addressed in the current base rate case would become effective? If beyond October 1, 2009, please explain your answer fully. (b) Have any credit rating agencies announced that APS's debt would be downgraded if APS's request for interim rates were to be denied? If so, please provide all such announcements. (c) Have any credit rating agencies announced that APS's debt would be downgraded if APS's request for interim rates were to be granted in an amount substantially lower than the $115 million requested by APS? If so, please provide all such announcements. (d) Has APS had any communications with any credit rating agencies wherein APS's request for interim rates was discussed? If not, explain fully why not. If so, please identify the dates, persons involved, and substance of all such communications. (e) Has APS advised any of the credit rating agencies that the approximately 4 mill PSE Adjustor was going to expire after APS collected the $46 million of fuel and purchased power cost? If not, explain fully why not. If so, please identify the dates, persons involved, and substance of all such communications. (f) Please identify when the PSE Adjustor expired, and/or when APS currently expects it to expire.

Response:

(a) APS is still hoping to have rates effective by October 1, 2009.
(b) No.
(c) No.
(d) Yes. We notify them of regulatory filings. We have no records of specific dates. Persons involved in such discussions could be Don Brandt, James Hatfield, Barbara Gomez, and James McGill.
(e) Yes. See response to (d)
(f) The PSA expired with the last billing cycle of July, 2008.

Witness: Donald Brandt

ARIZONA CORPORATION COMMISSION
STAFF'S SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
JULY 31, 2008

Staff Interim 2.76 Does APS believe that, without interim rates, it would be facing a cash flow emergency in 2008 or 2009? If so, please provide all quantitative information and other documentation relied upon by APS for its expectation of a cash flow emergency without interim rates. If not, explain fully why not.

Response: No. The Company has $900 million in committed credit facilities available to it through 11/2010.

Witness: Donald Brandt

ARIZONA CORPORATION COMMISSION
STAFF'S SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172 – INTERIM RATES
JULY 31, 2008

Staff Interim 2.24 Refer to page 13, paragraph 29, of Mr. Brandt's 6/6/08 affidavit. (a) Please identify and describe in detail the two instances in which the Company's ability to access the debt markets have been limited in 2007. (b) Have there been any instances in 2008 in which the Company's ability to access the debt markets have been limited? If so, please identify, quantify and explain fully each such instance.

Response:

(a) In August and December 2007. Our ability to issue commercial paper was eliminated due to the volatility in the credit markets resulting from the sub-prime mortgage crisis.

(b) Yes. Again, our ability to issue commercial paper has been periodically impacted throughout 2008.

In each instance, APS borrowed under their revolving credit facilities which currently have similar pricing to commercial paper.

Witness: Donald Brandt

ARIZONA CORPORATION COMMISSION
STAFF'S SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172 – INTERIM RATES
JULY 31, 2008

Staff Interim 2.19 Refer to page 12, paragraph 26, of Mr. Brandt's 6/6/08 affidavit. (a) When will the $400 million of equity be infused into APS? (b) Does the timing of the equity infusion have any impact on APS's FFO/Debt ratio? If not, explain fully why not. If so, please identify, quantify and explain the impacts.

Response:

(a) We expect PNW to issue up to $400 million of equity before year-end 2009 and immediately infuse the proceeds into APS.

(b) Yes. The debt level will increase if there is no equity infusion which will decrease FFO/Debt by approximately 2%. Attached as APS13333 is an approximation of the FFO/Debt impact.

Witness: Donald Brandt

Funds from Operations to Debt
Present Rates - No Equity Infusion
($ Millions)

APS	12/31/2008			12/31/2009		
	With $400m Equity Infusion	Impacts of Removing Equity Infusion	Without $400m Equity Infusion	With $400m Equity Infusion	Impacts of Removing Equity Infusion	Without $400m Equity Infusion
FFO	$ 908	$ (7)	$ 901	$ 781	$ (15)	$ 766
Adjusted debt	$ 3,942	$ 400	$ 4,342	$ 4,445	$ 400	$ 4,845
FFO to debt	23.0%		20.8%	17.6%		15.8%

(400m more debt x 6.25% = 25m higher interest x 60% = $15 after tax x 6/12 = $7m lower ffo for 2008)

APPENDIX A

LIST OF EMERGENCY RATE APPLICATIONS SINCE 1983

Company	Decision No.	Year Decided	Issue
Arizona Public Service Company	53909	1983	Negative indicators (cash coverage of interest, cash coverage of common earnings, and internal cash generation) led to risk of APS' commercial paper rating being downgraded leading to borrowing with higher interest rates and leading to a possible downgrade to "BB" status. APS undergoing a massive construction program, including the three nuclear generating units at Palo Verde. A $60 million increase was approved but APS was ordered to cease accruals of AFUDC on $327 million of construction associated with Palo Verde Unit 1 during the effective period of the interim rates. APPROVED
E & R Water Company, United Utilities Inc., Desert Utilities Inc., Williamson Waterworks Inc., Pinewood Sewer Company Inc., High Country Water Inc., C & S Water Company Inc., and Pine Oak Water Company Inc.	57768	1991	All of these utilities were owned by Utility Systems Group Inc. ("USG") through stock holdings acquired in 1988 and 1989. USG also owned Utility Management and Operations Services ("UMOS"), which appeared to be an unregulated subsidiary. All of the utilities were in poor condition, such as sewer pipes being used to deliver water. In addition, financial impacts from UMOS hurt the utilities' financial health. Applicant admitted to paying more for the utilities than what they were worth and Staff and RUCO indicated that the Applicant likely caused whatever financial emergency existed. The Commission rejected USG's arguments that there was a sudden and unforeseen emergency or its contention of a negative cash flow from operations. This Decision references Decision No. 57049 (1990), where the Commission denied emergency rate relief for Pinewood Sewer Company. DENIED
Mountain View Water Company	57841	1992	Water quality problems and major operation and maintenance deficiencies along with a cease and desist order issued from the Arizona Department of Environmental Quality ("ADEQ"). The utility has been operating at a loss for the last 16 years, and was being subsidized for its operations. The utility also experienced water shortages over the summer the past six to seven years. Commission found an emergency existed. APPROVED.
Golden Corridor Water Company	58672	1994	A lightning surge destroyed a motor servicing the primary well. Immediate repairs were required. $3,075.11 was going to be needed to make the repairs. The utility's back-up well was inoperable. The utility was able to pay for the repairs in full and some evidence suggested a water leak had caused an electrical short in the motor. No emergency was found because the well was operational and charges for the repairs were paid-in-full. The investment in the new well was to be addressed in the utility's next permanent rate case. DENIED.

APPENDIX A

LIST OF EMERGENCY RATE APPLICATIONS APPROVED SINCE 1983 (continued)

Company	Decision No.	Year Decided	Issue
United Utilities – Mesa Del Caballo System	58677	1994	Severe water shortage problems in the area. Water needed to be purchase from the Town of Payson. The issues in this case appeared to be more about the design and duration of the emergency surcharge, rather than whether an emergency existed. A three-year surcharge was approved from May to October of each year for those using over 4,000 gallons. APPROVED.
Congress Water Company	58777	1994	A non-profit utility had a back-up well pumping at 28 percent of capacity. $23,321.40 needed to make the necessary repairs to the well. Repairs were also needed to a booster pump and telemetry control box, apparently due to a lightning strike. The utility did not have the cash reserves nor did it have access to other funds to pay for the improvements to the well, booster pump and control box without additional funding. An emergency found, based on the fact that because of the lack of sufficient cash reserves and the need to ensure uninterrupted service. APPROVED.
Lakewood Water Company	58900	1994	Emergency petition for a surcharge to recover the increased costs for laboratory analyses required by ADEQ. The applicant subsequently withdrew its application. DISMISSED WITHOUT PREJEDICE.
Valle Verde Water Company	58917	1994	Emergency surcharge requested to offset chemical analysis costs required by ADEQ. The utility subsequently withdrew its application. DISMISSED WITHOUT PREJUDICE.
Sedona Venture (Sewer)	59122	1995	Storm damage to the utility's water and sewer lines, near a bridge that was washed out. No emergency determined because the Company was not insolvent and that service should be maintained in the foreseeable future. The Company would have $14,320 cash flow to make payments on a $36,000 loan for repairs. DENIED.
Mountain View Water Company	59250	1995	The utility applied for an emergency increase to pay for the hauling of drinking and cooking water. The utility had then-existing compliance issues with both the Commission and ADEQ, including ADEQ ordering the utility to haul drinking and cooking water on a weekly basis. The utility advocated for interim rates to fund a particular method of hauling. The Commission denied granting of relief for hauling because the utility knew of problems since 1984. Numerous other compliance issues. The Commission did approve a surcharge for the limited purpose of payment for a well pump and motor. APPROVED IN PART AND DENIED IN PART.

APPENDIX A

LIST OF EMERGENCY RATE APPLICATIONS APPROVED SINCE 1983 (continued)

Company	Decision No.	Year Decided	Issue
George M. Papa dba George M. Papa Water Company	59650	1996	An abundance of operational and management problems, numerous outstanding amounts owed to local taxing authorities, lack of storage facilities, and other deficiencies. APPROVED
Bellemont Water Company	60083	1997	Water production on the utility's wells fell to 250 gpm from 420 gpm, forcing the utility to purchase water from Atchison, Topeka and Santa Fe Railway Company to meet its needs. The Utility had to pay an extra $1.50 per 1,000 gallons pumped, plus electricity and maintenance for the Railway's well. Staff proposed a different method of recovering emergency rates, which was adopted by the Commission. APPROVED.
Diamond Valley Water Users Corporation	60394	1997	Poor physical condition and rapid deterioration of the utility's distribution system, due to the entire system being constructed in substandard fashion. Also, Yavapai County was re-grading roadways where the utility's mains were located. As a result, the utility was being requested to lower the depth of its mains in these roadways. But because the utility had a positive cash flow of $2,300 each month to make improvements, and because the utility was not insolvent and could maintain service, Staff recommended denial. Staff's position was adopted by the Commission. DENIED.
Holiday Hills Water Company	60572	1998	The utility had a history of repeated water outages and shortages. One of the two wells repeatedly ran dry. Water hauling was necessary, with water purchased from the City of Prescott. Water main line replacements also needed, and damaged meters. The City of Prescott was threatening to deny the utility any more water unless payments for outstanding amounts owed were made. Outstanding amounts owed to other entities making repairs to the system. APPROVED.
Far West Water Company	61833	1999	Utility's groundwater supplies contained a high level of total dissolved solids that affected the taste and affected appliances that used the water. To allow enough cash flow to finance construction of a water treatment plant and related facilities so that Colorado River water can be used. APPROVED

APPENDIX A

LIST OF EMERGENCY RATE APPLICATIONS APPROVED SINCE 1983 (continued)

Company	Decision No.	Year Decided	Issue
Vail Water Company	61930	1999	Operating shortfalls forced the utility to borrow $150,000 from its shareholders. The utility was alleging it would need to borrow an additional $93,000 if interim rates are not approved. The utility further alleged it would not be able to perform its services as a public service corporation and that it was insolvent. The Commission found that the utility had not met its burden to show an emergency existed, mainly because the utility continued to incur expenses for disallowed items. DENIED
Thim Utility Company, E&T Division	62651	2000	High nitrate levels from the utility's one well forced purchase of twice as much water from the City of Tucson than what was anticipated. APPROVED
Oatman Water Company	62953	2000	Decline in the aquifer lead to the utility's well pumping only 3 gallons per minute at time of the hearing. Financing needed to haul water and drill two additional wells. A previous interim rate order was approved (Decision No. 62772) but additional relief still needed. APPROVED
Forty Niner Water Company	65352	2002	Persistent drought conditions and lack of conservation lead to the utility having to purchase water from the City of Tucson. Emergency rates needed to cover the costs of the purchases and the hook-up with the City of Tucson. APPROVED
Pine Water Company	65914	2003	Chronic water supply problems in the area the utility serves. Ongoing drought conditions and continuing low rainfall exacerbating the utility's ability to supply water to its customers. Water hauling necessary until a construction of a water pipeline from a neighboring utility to supply water was completed, along with the fixing of leaks and drilling of new wells. APPROVED
Mount Tipton Water Company	66732	2003	The utility was unable to pay its WIFA loan when payments were due. The utility had pursued formation of an improvement district, but formation was not approved. The interest rate on the WIFA loan remained at 8.5 percent versus the 4.75 percent reduction that would have occurred had a district been formed. The utility also had recently acquired another utility (Dolan Springs) that owed considerable back taxes. APPROVED

APPENDIX A

LIST OF EMERGENCY RATE APPLICATIONS APPROVED SINCE 1983 (concluded)

Company	Decision No.	Year Decided	Issue
Naco Water Company	67984	2005	Increases in construction costs for upgrades to the utility's system. Additional costs to relocate a portion of its system to accommodate a road-widening project. Additional water storage and a new well needed to address the fact that the utility's Well No. 4 was going dry. The utility received emergency interim rate relief in Decision No. 61609 (1999) due to ongoing operational and financial problems. APPROVED
Sabrosa Water Company	67990	2005	Problems included inadequate water supplies, marginal to poor water quality, poorly maintained equipment, a series of financial and legal problems as a result of the owner abandoning the system and rates that do not allow for the operation and maintenance of the water system. APPROVED
Johnny A. McLain dba Cochise, Horseshoe Ranch, Coronado Estates, Cyrstal, Mustang, Miracle Valley and Sierra Sunset	N/A	N/A	Recommended Opinion and Order in Docket Nos. W-01646A-06-0010 outlines numerous operational and maintenance problems, outages, and other deficiencies. All systems part of a bankruptcy proceeding. TO BE DECIDED

Moody's Investors Service

Global Credit Research
Credit Opinion
28 JUL 2008

Credit Opinion: Arizona Public Service Company

Arizona Public Service Company

Phoenix, Arizona, United States

Ratings

Category	**Moody's Rating**
Outlook	Stable
Issuer Rating	Baa2
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Subordinate Shelf	(P)Baa3
Commercial Paper	P-2
Parent: Pinnacle West Capital Corporation	
Outlook	Stable
Issuer Rating	Baa3
Sr Unsec Bank Credit Facility	Baa3
Senior Unsecured Shelf	(P)Baa3
Subordinate Shelf	(P)Ba1
Preferred Shelf	(P)Ba2
Commercial Paper	P-3

Contacts

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Key Indicators

Arizona Public Service Company

ACTUALS	**1Q08 LTM**	**2007**	**2006**	**2005**
(CFO Pre-W/C + Interest) / Interest Expense [1][2]	**4.4x**	**4.2x**	**4.4x**	**3.6x**
(CFO Pre-W/C) / Debt [2]	**19.6%**	**18.3%**	**19.0%**	**14.5%**
(CFO Pre-W/C - Dividends) / Debt [2]	**14.1%**	**14.0%**	**14.5%**	**9.7%**
(CFO Pre-W/C - Dividends) / Capex [2]	**56.0%**	**58.7%**	**79.0%**	**53.1%**
Debt / Book Capitalization	**45.9%**	**45.9%**	**46.0%**	**47.5%**
EBITA Margin	**21.7%**	**22.6%**	**23.9%**	**20.9%**

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items [2] Changes in risk management and trading assets and liabilities are excluded from CFO Pre-W/C

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Corporate Profile

Arizona Public Service (APS: Baa2 senior unsecured, stable) is a vertically integrated electric utility that provides electric service to most of the state of Arizona with the major exceptions of about one-half of the Phoenix metropolitan area and the Tucson metropolitan area. APS is the primary subsidiary of Pinnacle West Capital Corporation (Pinnacle: Baa3 senior unsecured, stable), a holding company that through its other subsidiaries sells energy related products and services and develops residential and commercial real estate.

Recent Events

On July 25, 2008 Moody's revised the outlooks for APS and Pinnacle to stable from negative. The revision in outlook was a result of the companies' stable financial performance and also reflects our opinion of APS' improved prospects for more timely recovery of certain costs than had historically been the case. Our view is based on recent regulatory decisions involving recovery mechanisms for the cost of fuel and purchased power and transmission as well as recovery mechanisms for certain growth related costs. The outlook revision also recognized APS' demonstrated intent to attempt to minimize regulatory lag by filing for additional rate relief as soon as practicable.

Regulatory Activity

Approval of Line Extension Fees

In February 2008 the Arizona Corporation Commission (ACC) approved an amendment to APS' line extension schedule which eliminated certain free footage allowances and permitted APS to collect, on a current basis, costs relating to line extensions, which are estimated to be approximately $3,500 - $5,000 per new meter set (pre-tax). Moody's views the incremental (after-tax) cash flow resulting from these fees as recurring, and we have adjusted our credit metrics to reflect them as operating cash flows.

General Rate Case Filing

In June 2008, APS filed for a $278.2 million net rate increase (approximately 8.5% from existing customers) comprised of a $264.3 million non-fuel related increase and a $13.9 million net fuel-related increase. APS has proposed to collect up to $53 million of the increase specifically from new customers. The fuel increase request is net of approximately $170 million currently being collected in APS rates through its power supply adjustor (PSA) mechanism. APS' June filing is based on a test year ended December 2007. The request has been accepted by ACC Staff. A procedural schedule has been proposed with hearings in April 2009 and a decision expected in the latter part of 2009.

Request for Interim Increase

Also in June 2008, APS filed a request for an interim base rate increase of $.003987 per kWh to become effective upon the expiration of the $.003987 per kWh power supply adjustor surcharge currently in APS' rates. APS estimates the current surcharge will remain in effect through July. A procedural schedule has been set for this request, with hearings scheduled for September 2008 with a decision anticipated shortly thereafter.

Palo Verde

In February 2007, Nuclear Regulatory Commission (NRC) placed Palo Verde Unit 3 (PVU3), into the "multiple/repetitive degraded cornerstone" column of the NRC's action matrix, which has resulted in an enhanced inspection regimen and some increased operating costs for APS as it seeks to improve its processes at all three Palo Verde units. In February 2008, the NRC issued its revised confirmatory action letter, and as required, on March 31, 2008, APS submitted its revised improvement plan. The NRC will continue to provide increased oversight at Palo Verde until the facility has demonstrated sustained performance improvement. APS anticipates that this process will continue into 2009.

While operating performance at Palo Verde has improved, capacity factors continue to be impacted by planned outages (including a steam generator replacement in 2007) that have been extended by additional inspections. In 2007, the plant's average capacity factor was 79.0% versus 70.7% in 2006 and 77.4% in 2005. For the first quarter of 2008, the nuclear capacity factor was 93%.

Rating Rationale

The Baa2 rating for the senior unsecured obligations of APS reflects the stability of its regulated cash flows, the economic strength of its service territory, its regulatory environment, cash flow credit metrics that are appropriate

for the rating, and its position as a subsidiary of Pinnacle. The rating and outlook consider the traditionally challenging regulatory environment in Arizona, but also contemplates recent ACC decisions and regulatory activities that appear intended to reduce regulatory lag and provide more timely recovery of certain costs.

Given APS' current significant capital expenditure program, the company will require continued, timely regulatory support to maintain credit metrics that are appropriate for its rating. The stable outlook assumes APS will be reasonably successful in managing its regulatory relationships with an objective of achieving more timely recovery and an opportunity to earn a fair return. The rating also incorporates an expectation that APS will maintain a balanced approach with regards to financing its capital expenditures with a goal of maintaining or improving its current level of financial strength.

The most important drivers of the rating and outlook are as follows:

Regulatory Environment

Almost all of APS' operations are regulated which is generally viewed as positive for credit quality as regulated cash flows tend to be more stable and predictable than those of unregulated companies. This key factor is tempered somewhat by the historically challenging regulatory environment in Arizona, which Moody's ranks as below average for U.S. regulatory jurisdictions in terms of supportiveness or predictability and stability of regulated cash flows.

APS' operations are regulated by the ACC, an elected commission that has tended to render its decisions after prolonged consideration. Although regulatory lag remains a significant concern, recent decisions with regards to costs for fuel and purchased power and transmission, and certain growth related expenditures should reduce the time to recover some of these items.

General Regulatory Lag

APS' rate case activity is illustrative of an environment where there has tended to be below average assurance of timely recovery of costs and the ability to earn a reasonable return on investment. APS' 2003 rate case was not concluded until April 2005, and the increase received was less than half of the amount requested; the significant delay and relatively modest allowed increase resulted in the need for APS to quickly file another rate case in January 2006.

APS' January 2006 rate case was decided somewhat more quickly with a decision rendered in June 2007 wherein the utility received approximately three quarters of its requested increase; however, the allowed increase was almost entirely related to increased costs for fuel and purchased power. Of the $120 million requested for non-fuel items, only $7 million was approved. As a result, APS filed another general rate case as soon as practicable, based on a test year-ending September 2007. APS subsequently agreed with ACC Staff to re-file its rate increase request based on a test year-ending December 2007. Given the amount of time generally required to decide rate cases in Arizona, Moody's estimates that new rates will not be implemented until the latter part of 2009.

Reduced Regulatory Lag for Certain Items

The ACC's June 2007 decision included a significantly improved mechanism for the recovery of fuel and purchased power costs, incorporating a forward estimate of fuel costs in addition to the continued recovery of past deferrals. Fuel and purchased power costs have been among APS' most volatile operating expenses and Moody's views the ACC's recent approach to this problem as supportive of the utility's credit profile. However, we note that APS fuel recovery factor remains subject to an annual cap, potentially delaying recoveries beyond a one-year true-up period, and subject to a 90/10 sharing mechanism wherein 10% of costs are not able to be recovered.

In June 2008, APS requested an interim base rate increase that would take effect upon expiration in July 2008 of a surcharge being collected under the fuel clause adjustment mechanism. The request could potentially allow base rate cost recovery, subject to refund, prior to the completion of the next general rate case. This could result in a measure of rate stability as there could potentially be no immediate incremental increase to customers, and there would likely ultimately be a smaller base rate increase. Since the ACC and interested parties needed more time to consider this request, a decision is now expected late September to mid October. If implemented new rates could be in place November 1 when lower winter rates go into effect, thereby allowing some degree of rate stability. Moody's notes that the ACC has granted interim increases in the recent past. Moody's views mechanisms designed to reduce the time required to recover a utility's costs, such as the requested interim base rate increase a positive for credit quality.

In its June 2007 order, the ACC requested that APS propose mechanisms that could potentially allow growth to

pay for itself, rather than being paid by the current customer base. In February 2008, the ACC approved an amendment to APS' line extension schedule that should provide an almost immediate recovery of the cost of certain growth related capital investment reducing the amount of external financing needed to support these expenditures. Moody's views this revision as positive for credit, virtually eliminating the normal regulatory lag that would otherwise be associated with seeking recovery of these expenditures.

In its 2005 order, the ACC authorized a transmission tracking adjustment (TCA) mechanism designed to allow retail transmission charges to track those authorized by the FERC. The TCA was initially implemented in March 2008, and timely adjusted following an automatic adjustment in FERC transmission rates in June 2008.

Service Territory Growth Slowing

Growth in APS' service territory has slowed significantly below the 4-5% level experienced in 2005 and 2006. In 2007, customer growth was approximately 3%; for the first quarter of 2008 customer growth slowed to 2% and is not expected to return to historical heights over the near-to-medium term. Although, a growing customer base can provide a source of increased revenue, assuming timely recovery of increased growth related investment and increased costs for fuel and purchased power, it also has resulted in a continuing need for capital investment and regulatory relief. The stable outlook assumes APS will continue to take a balanced approach with regards to the funding of its capital expenditures. Moody's also believes a sustained period of slower growth could potentially temper APS need for capital investment which could reduce its financing requirements.

Financial Metrics

In 2004 and 2005, APS' key financial metrics reflected the fact that it had been unable to recover fully increased costs for fuel, purchased power and capital spending on a timely basis. For example, the ratio of cash from operations prior to changes in current assets and liabilities (CFO pre-WC) / debt (incorporating Moody's standard analytic adjustments) dropped into the mid-teens. Financial metrics improved in 2006 and 2007 with CFO pre - WC / debt moving to the upper-teens as fuel recovery improved. These metrics are now toward the middle-to-upper end of the 13% to 25% range identified in Moody's Rating Methodology for Global Electric Utilities for Baa rated entities on a stand-alone basis within the medium risk category. Cash flow credit metrics are expected to remain in that range over the near-to-medium term reflecting more timely cost recovery of certain items and assuming capital expenditures are financed in a manner that is also supportive of APS current financial strength and flexibility. In general, Moody's would look for APS to have financial metrics that are somewhat stronger than comparably rated utility operating companies that operate in regulatory environments that have historically been more supportive of credit quality.

Subsidiary of Pinnacle West

Pinnacle, APS' parent company, conducts a modest amount of non-regulated activities including power marketing and trading, sales of energy related products and services, and residential and commercial real estate development through subsidiaries including SunCor Development Company (real estate). However, for the past several years almost all of Pinnacle's cash from operations has been generated by APS. Over the near-to-medium term, Pinnacle's non-regulated businesses, are not expected to meaningfully contribute to, or detract from, consolidated cash flows. Although residential real estate sales slowed considerably in 2006, 2007 and continuing into 2008, Pinnacle's joint venture strategy with other developers, combined with its successfully completed asset sales program (implemented 2003-2005) has significantly reduced its exposure to this volatile sector. The parent company also maintains a modest amount of leverage with holding company debt at less than 10% of consolidated debt.

Liquidity Profile

APS' Prime-2 short-term rating for commercial paper reflects the relatively stable and predictable cash flow provided by its regulated electric utility operations.

For the year ended December 2007, APS' cash flow from operations of approximately $765 million covered approximately 72% of its outlays, including capital expenditures of approximately $900 million and dividends to Pinnacle of $170 million. The shortfall was funded via a combination of internal and external sources of cash including $218 million of short term debt proceeds, approximately $40 million of equity contributions from Pinnacle and cash on hand.

For the next several years, APS' capital expenditures are expected to be in the range of $1.0 billion per year, primarily to expand APS' transmission and distribution network to meet growing customer needs, but also to upgrade its existing utility properties and for other environmental purposes. Funding for these increased capital

expenditures is expected to be provided via a combination of internal and external sources of cash, including operating cash flow, equity contributions from Pinnacle and long and short term debt financing.

Over the last several years, APS has paid dividends to Pinnacle of $170 million per year. Moody's expects APS' dividends are likely to remain near this level in 2008 and over the medium term.

APS' pattern of cash flow is seasonal as the peak of electric demand occurs during the summer months due to high air conditioning load that exists in its service territory. As a result, the bulk of its commercial paper borrowings typically occur in the second and third quarters of each year. As of March 31, 2008, APS had $90 million of commercial paper and $100 of short-term debt outstanding under its revolving credit facility.

APS has historically maintained a very modest level of cash on its balance sheet; as of March 31, 2008, APS had reported cash and cash equivalents of approximately $8 million.

APS' commercial paper program is sized at $250 million and is currently supported by two committed lines of credit totaling $900 million, a $400 million line that expires in December 2010 and a $500 million line that expires in September 2011. As of March 31, 2008, APS had approximately $100 million of borrowings under its credit facilities. Overall availability under these credit facilities was $796 million, of which $90 million was back-stopping commercial paper outstanding. Both credit agreements have one financial covenant that requires the ratio of debt to total capitalization not to exceed 65%. As of March 31, 2008, APS' debt to total capitalization ratio, calculated in accordance with the credit documents, was approximately 47%. The credit agreements do not require a Material Adverse Change (MAC) representation for revolver borrowings. No rating triggers exist in any APS credit facilities though interest costs may increase under various financing agreements if a downgrade occurs. APS nearest long term debt maturity is $400 million of unsecured notes due in 2011. In 2010, APS must replace letters of credit supporting approximately $200 million of variable rate pollution control bonds.

APS' Prime-2 rating for its short term obligations assumes that the company will manage the amount of commercial paper and other near term obligations outstanding within the limits of its readily available sources of cash, including its committed bank credit facilities.

Rating Outlook

The stable outlook reflects the nature of APS' predominately regulated cash flows and Moody's view that its improved cash flow financial metrics are likely to be sustainable. The outlook assumes APS' will be reasonably successful in managing its regulatory relationships and that capital expenditures will be financed in a balanced manner with a goal of maintaining or improving APS current position of financial strength.

What Could Change the Rating - Up

APS' rating is not likely to be revised upward in the near-to-medium term. Longer term, if there is an increase in supportive regulatory treatment resulting in material, timely rate increases, or if there are material reductions in costs or leverage such that Moody's could anticipate key financial ratios improving significantly from their current levels, if for example, a ratio of CFO pre -WC / debt could be maintained in the mid twenty percent range.

What Could Change the Rating - Down

A downgrade could result if Palo Verde experiences an extended outage and APS is unable to recover, in a timely manner, higher maintenance and purchased power costs, or if APS' regulatory lag for capital spending becomes more pronounced. A downgrade could result if Moody's expects a sustained weakening of financial metrics, if for example, the ratio of CFO pre -WC / debt would remain in the mid-teens for an extended period.

Rating Factors

Arizona Public Service Company

62000

Select Key Ratios for Global Regulated Electric Utilities

Rating	Aa	Aa	A	A	Baa	Baa	Ba	Ba
Level of Business Risk	Medium	Low	Medium	Low	Medium	Low	Medium	Low

CFO pre-W/C to Interest (x) [1]	>6	>5	3.5-6.0	3.0-5.7	2.7-5.0	2-4.0	<2.5	<2
CFO pre-W/C to Debt (%) [1]	>30	>22	22-30	12-22	13-25	5-13	<13	<5
CFO pre-W/C - Dividends to Debt (%) [1]	>25	>20	13-25	9-20	8-20	3-10	<10	<3
Total Debt to Book Capitalization (%)	<40	<50	40-60	50-70	50-70	60-75	>60	>70

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

ARIZONA CORPORATION COMMISSION
STAFF'S SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172-INTERIM RATES
JULY 31, 2008

Staff Interim 2.97 Without any interim rate increase, will APS be able to provide safe and reliable electric service to its customers in 2008 and 2009? If not, explain fully why not.

Response: While the Company hopes that it is able to continue to provide safe and reliable electric service to customers in 2008 and 2009 and intends to do so, the Company's interim base rate request is intended to support its overall financial health so that its ability to offer reliable electric service will not be jeopardized in the future.

Witness: Donald Brandt

ARIZONA CORPORATION COMMISSION
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E-01345A-08-0172
JULY 31, 2008

Staff Interim 2.74 Does APS have any estimates of the cost of obtaining a performance bond or other form of financial assurance that APS would be able to make refunds of any emergency rate relief that might be granted by the Commission? If so, please provide details for each type of performance bond or other form of financial assurance that APS has knowledge of.

Response: The estimated cost for either a bond or a letter of credit would be in the range of 1% of its face value.

Witness: Donald Brandt

ARIZONA CORPORATION COMMISSION
STAFF'S SECOND SET OF DATA REQUESTS TO
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E-01345A-08-0172
JULY 31, 2008

Staff Interim 2.73 If APS is granted any interim rate relief, please list all steps and measures that APS would take in order to assure that it would be able to subsequently make refunds that might be ordered by the Commission at a later date.

Response: Although APS does not believe that it is legally obligated or necessary to post a bond, APS would nonetheless be willing to provide a bond or a letter of credit guaranteeing the refunds, if ordered to do so by the Commission.

Witness: TBD

Moody's Investors Service

Global Credit Research
Credit Opinion
28 JUL 2008

Credit Opinion: Pinnacle West Capital Corporation

Pinnacle West Capital Corporation

United States

Ratings

Category	**Moody's Rating**
Outlook	Stable
Issuer Rating	Baa3
Sr Unsec Bank Credit Facility	Baa3
Senior Unsecured Shelf	(P)Baa3
Subordinate Shelf	(P)Ba1
Preferred Shelf	(P)Ba2
Commercial Paper	P-3
Arizona Public Service Company	
Outlook	Stable
Issuer Rating	Baa2
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Subordinate Shelf	(P)Baa3
Commercial Paper	P-2

Contacts

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Key Indicators

Pinnacle West Capital Corporation

ACTUALS	**1Q08 LTM**	**2007**	**2006**	**2005**
(CFO Pre-W/C + Interest) / Interest Expense [1][2]	**4.0x**	**3.9x**	**4.2x**	**3.7x**
(CFO Pre-W/C) / Debt [2]	**17.5%**	**17.2%**	**18.9%**	**16.4%**
(CFO Pre-W/C - Dividends) / Debt [2]	**12.8%**	**12.5%**	**14.1%**	**11.8%**
(CFO Pre-W/C - Dividends) / Capex [2]	**57.3%**	**57.6%**	**75.2%**	**69.6%**
Debt / Book Capitalization	**48.9%**	**48.5%**	**47.4%**	**48.0%**
EBITA Margin	**19.2%**	**20.2%**	**21.6%**	**18.9%**

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items [2] Changes in risk management and trading assets and liabilities are excluded from CFO Pre-W/C

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Corporate Profile

Pinnacle West Capital Corporation (Pinnacle: Baa3 senior unsecured, stable) is a holding company whose principal subsidiary, Arizona Public Service Corporation (APS: Baa2 senior unsecured, stable), is a vertically integrated electric utility that provides electric service to most of the state of Arizona with the major exceptions of about one-half of the Phoenix metropolitan area and the Tucson metropolitan area. Pinnacle's other subsidiaries are engaged in the sale of energy related products and services and the development of residential and commercial real estate.

Recent Events

On July 25, 2008 Moody's revised the outlooks for APS and Pinnacle to stable from negative. The revision in outlook was a result of the companies' stable financial performance and also reflects our opinion of APS' improved prospects for more timely recovery of certain costs than had historically been the case. Our view is based on recent regulatory decisions involving recovery mechanisms for the cost of fuel and purchased power and transmission as well as recovery mechanisms for certain growth related costs. The outlook revision also recognized APS' demonstrated intent to attempt to minimize regulatory lag by filing for additional rate relief as soon as practicable.

Regulatory Activity

Approval of Line Extension Fees

In February 2008 the Arizona Corporation Commission (ACC) approved an amendment to APS' line extension schedule which eliminated certain free footage allowances and permitted APS to collect, on a current basis, costs relating to line extensions, which are estimated to be approximately $3,500 - $5,000 per new meter set (pre-tax). Moody's views the incremental (after-tax) cash flow resulting from these fees as recurring, and we have adjusted our credit metrics to reflect them as operating cash flows.

General Rate Case Filing

In June 2008, APS filed for a $278.2 million net rate increase (approximately 8.5% from existing customers) comprised of a $264.3 million non-fuel related increase and a $13.9 million net fuel-related increase. APS has proposed to collect up to $53 million of the increase specifically from new customers. The fuel increase request is net of approximately $170 million currently being collected in APS rates through its power supply adjustor (PSA) mechanism. APS' June filing is based on a test year ended December 2007. The request has been accepted by ACC Staff. A procedural schedule has been proposed with hearings in April 2009 and a decision expected in the latter part of 2009.

Request for Interim Increase

Also in June 2008, APS filed a request for an interim base rate increase of $.003987 per kWh to become effective upon the expiration of the $.003987 per kWh power supply adjustor surcharge currently in APS' rates. APS estimates the current surcharge will remain in effect through July. A procedural schedule has been set for this request, with hearings scheduled for September 2008 and a decision anticipated shortly thereafter.

Palo Verde

In February 2007, Nuclear Regulatory Commission (NRC) placed Palo Verde Unit 3 (PVU3), into the "multiple/repetitive degraded cornerstone" column of the NRC's action matrix, which has resulted in an enhanced inspection regimen and some increased operating costs for APS as it seeks to improve its processes at all three Palo Verde units. In February 2008, the NRC issued its revised confirmatory action letter, and as required, on March 31, 2008, APS submitted its revised improvement plan. The NRC will continue to provide increased oversight at Palo Verde until the facility has demonstrated sustained performance improvement. APS anticipates that this process will continue into 2009.

While operating performance at Palo Verde has improved, capacity factors continue to be impacted by planned outages (including a steam generator replacement in 2007) that have been extended by additional inspections. In 2007, the plant's average capacity factor was 79.0% versus 70.7% in 2006 and 77.4% in 2005. For the first quarter of 2008, the nuclear capacity factor was 93%.

Rating Rationale

The Baa3 rating for the senior unsecured obligations of Pinnacle reflects the stability of its regulated cash flows, the economic health of APS' service territory, its regulatory environment, cash flow credit metrics that are appropriate for the rating, and its modest exposure to a currently weak real estate market. The rating and outlook consider the traditionally challenging regulatory environment in Arizona, but also contemplates recent ACC decisions and regulatory activities that appear intended to reduce regulatory lag and provide more timely recovery of certain costs.

Given APS' current significant capital expenditure program, the company will require continued, timely regulatory support to maintain credit metrics that are appropriate for its rating. The stable outlooks for APS and Pinnacle assume APS will be reasonably successful in managing its regulatory relationships with an objective of achieving more timely recovery and an opportunity to earn a fair return. The rating also incorporates an expectation that APS will maintain a balanced approach with regards to financing its capital expenditures with a goal of maintaining or improving its current level of financial strength.

The most important drivers of the rating and outlook are as follows:

Predominately Regulated Operations

Pinnacle engages in a modest amount of non-regulated activity; however, it currently derives almost all of its operating cash flow from its regulated electric utility subsidiary APS. Pinnacle's non-regulated operations include a limited amount of energy trading, sales of energy-related products and services and commercial and residential real estate development primarily in Arizona and the southwest. Although residential real estate sales have slowed considerably in 2006, 2007 and in 2008, Pinnacle's joint venture strategy with other developers, combined with its successfully completed asset sales program (implemented 2003-2005) has significantly reduced its exposure to this volatile sector. In 2006 and 2007, as expected, these operations contributed only modestly to consolidated cash flows. Pinnacle anticipates continued weak real estate markets in 2008 and 2009.

Regulatory Environment

Almost all of APS' operations are regulated which is generally viewed as positive for credit quality as regulated cash flows tend to be more stable and predictable than those of unregulated companies. This key factor is tempered somewhat by the historically challenging regulatory environment in Arizona, which Moody's ranks as below average for U.S. regulatory jurisdictions in terms of supportiveness or predictability and stability of regulated cash flows.

APS' operations are regulated by the ACC, an elected commission that has tended to render its decisions after prolonged consideration. Although regulatory lag remains a significant concern, recent decisions with regards to costs for fuel and purchased power and transmission, and certain growth related expenditures should reduce the time to recover some of these items.

General Regulatory Lag

APS' rate case activity is illustrative of an environment where there has tended to be below average assurance of timely recovery of costs and the ability to earn a reasonable return on investment. APS' 2003 rate case was not concluded until April 2005, and the increase received was less than half of the amount requested; the significant delay and relatively modest allowed increase resulted in the need for APS to quickly file another rate case in January 2006.

APS' January 2006 rate case was decided somewhat more quickly with a decision rendered in June 2007 wherein the utility received approximately three quarters of its requested increase; however, the allowed increase was almost entirely related to increased costs for fuel and purchased power. Of the $120 million requested for non-fuel items, only $7 million was approved. As a result, APS filed another general rate case as soon as practicable, based on a test year-ending September 2007. APS subsequently agreed with ACC Staff to re-file its rate increase request based on a test year-ending December 2007. Given the amount of time generally required to decide rate cases in Arizona, Moody's estimates that new rates will not be implemented until the latter part of 2009.

Reduced Regulatory Lag for Certain Items

The ACC's June 2007 decision included a significantly improved mechanism for the recovery of fuel and purchased power costs, incorporating a forward estimate of fuel costs in addition to the continued recovery of past deferrals. Fuel and purchased power costs have been among APS' most volatile operating expenses and Moody's views the ACC's recent approach to this problem as supportive of the utility's credit profile. However, we note that APS fuel recovery factor remains subject to an annual cap, potentially delaying recoveries beyond a one-year true-up period, and subject to a 90/10 sharing mechanism wherein 10% of costs are not able to be recovered.

In June 2008, APS requested an interim base rate increase that would take effect upon expiration in July 2008 of a surcharge being collected under the fuel clause adjustment mechanism. The request could potentially allow base rate cost recovery, subject to refund, prior to the completion of the next general rate case. This could result in a measure of rate stability as there could potentially be no immediate incremental increase to customers, and there would likely ultimately be a smaller base rate increase. Since the ACC and interested parties needed more time to consider this request, a decision is now expected late September to mid October. If implemented new rates could be in place November 1 when lower winter rates go into effect, thereby allowing some degree of rate stability. Moody's notes that the ACC has granted interim increases in the recent past. Moody's views mechanisms designed to reduce the time required to recover a utility's costs, such as the requested interim base rate increase a positive for credit quality.

In its June 2007 order, the ACC requested that APS propose mechanisms that could potentially allow growth to pay for itself, rather than being paid by the current customer base. In February 2008, the ACC approved an amendment to APS' line extension schedule that should provide an almost immediate recovery of the cost of certain growth related capital investment reducing the amount of external financing needed to support these expenditures. Moody's views this revision as positive for credit, virtually eliminating the normal regulatory lag that would otherwise be associated with seeking recovery of these expenditures.

In its 2005 order, the ACC authorized a transmission tracking adjustment (TCA) mechanism designed to allow retail transmission charges to track those authorized by the FERC. The TCA was initially implemented in March 2008, and timely adjusted following an automatic adjustment in FERC transmission rates in June 2008.

Service Territory Growth Slowing

Growth in APS' service territory has slowed significantly below the 4-5% level experienced in 2005 and 2006. In 2007, customer growth was approximately 3%; for the first quarter of 2008 customer growth slowed to 2% and is not expected to return to historical heights over the near-to-medium term. Although, a growing customer base can provide a source of increased revenue, assuming timely recovery of increased growth related investment and increased costs for fuel and purchased power, it also has resulted in a continuing need for capital investment and regulatory relief. The stable outlook assumes APS will continue to take a balanced approach with regards to the funding of its capital expenditures. Moody's also believes a sustained period of slower growth could potentially temper APS need for capital investment which could reduce its financing requirements.

Real Estate Exposure

SunCor Development Company (SunCor), Pinnacle's real estate development subsidiary, is exposed to the volatility inherent in the western real estate markets; however, currently this exposure is relatively modest. In 2005, SunCor completed the last phase of a three year accelerated asset sales program during which time it sent meaningful ($50-100 million per year) dividends to Pinnacle. In 2006 and 2007, SunCor sent Pinnacle a dividend of approximately $10 million. In 2008, only modest, if any, dividends are anticipated from SunCor which has been impacted by the general slowdown in the real estate market and lower residential sales. SunCor's commercial sales remained stronger than residential sales; however, several anticipated 2007 closings, including an office tower at Hayden Ferry Lakeside, were delayed due to conditions in the credit markets. SunCor successfully closed the Haden Ferry Lakeside transaction in June 2008.

SunCor mitigates its exposure to the more volatile aspects of the sector by developing its investments via joint ventures with participating land owners. The company's strategy involves generally making only modest investments until sales agreements are in place. In 2007, SunCor contributed approximately $24 million to Pinnacle's consolidated net income, versus approximately $60 million in 2006, and $55 million in 2005. In 2008, only minimal, if any, earnings are anticipated from SunCor. The subsidiary is not expected to be a significant driver of consolidated earnings or cash flow over the near-to-medium term. SunCor is also not expected to require any additional investment from Pinnacle as the subsidiary is expected to continue to self-fund its investments and has its own non-recourse credit facilities in place.

Financial Metrics

In 2004 and 2005, Pinnacle's key financial metrics reflected the fact that APS had been unable to recover increased costs for fuel and purchased power on a timely basis. For example, the ratio of cash from operations prior to changes in working capital (CFO pre-WC) to adjusted debt (incorporating Moody's standard analytic adjustments) dropped into the mid-teens in 2004 and 2005 then moving to the upper-teens in 2006 and 2007, as fuel recovery improved. These recent ratios are toward the middle of the 13% to 25% range identified in Moody's Rating Methodology for Global Regulated Electric Utilities for Baa rated utility companies within the medium risk category. Given Pinnacle's position toward the mid-to-upper end of the medium business risk category, these metrics are consistent with its Baa3 rating. Cash flow credit metrics are expected to remain in that range over the near-to-medium term, reflecting more timely cost recovery of certain items at APS and assuming capital expenditures are financed in a manner that is also supportive of Pinnacle's current financial strength and flexibility. In general, Moody's would look for Pinnacle to have financial metrics that are somewhat stronger than comparably rated utility parent companies that operate in more supportive regulatory environments and that have a lower level of overall business risk.

Liquidity Profile

As a holding company, Pinnacle's primary source of liquidity is the dividends it receives from its operating subsidiaries, primarily its utility subsidiary, APS. In 2006 and 2007, subsidiary dividends of approximately $180 million covered approximately 77% of Pinnacle's overhead costs, parent level interest expenses of approximately $17 million and common stock dividends of approximately $210 million.

While the dividends Pinnacle receives from SunCor have decreased considerably from approximately $100 million in 2003 to $10 million in 2006 and 2007, the annual dividends it receives from APS have been very stable at $170 million per year. Moody's expects APS' dividends are likely to remain near this level in 2008 and over the medium term.

Pinnacle's $250 million commercial paper program is supported by a $300 million revolving credit facility that expires December 2010. As of March 31, 2008, Pinnacle had approximately $145 million of commercial paper outstanding. APS also has its own $250 million commercial paper program that is supported by two of its own committed lines of credit totaling $900 million, a $400 million line that expires in December 2010 and a $500 million line that expires in September 2011. As of March 31, 2008, APS had approximately $100 million of borrowings under its credit facilities. Overall availability under these credit facilities was $796 million, of which $90 million was back-stopping commercial paper outstanding.

The credit agreements for both Pinnacle and APS have one financial covenant that requires the ratio of debt to total capitalization not to exceed 65%. At March 31, 2008, total debt to total capitalization was approximately 51% for Pinnacle and 47% for APS. None of the credit agreements for Pinnacle or APS require a Material Adverse Change (MAC) representation for revolver borrowings or rating triggers for early repayment though interest costs may increase under various financing agreements if a downgrade occurs. SunCor has its own $150 million secured revolving facility that terminates in December 2008, under which there was approximately $85 million outstanding as of December 2007. SunCor also had some, primarily two-year, construction loans aggregating under $150 million due primarily in 2008 and 2009. The SunCor loans and revolver are secured by specific interests in land, commercial properties, land contracts and/or homes under construction and are non-recourse to Pinnacle.

On a consolidated basis, capital expenditures in 2008 are expected to be approximately $1 billion, with approximately $50 million at SunCor. APS is expected to finance its capital expenditures from internal and external sources, including equity infusions from Pinnacle. SunCor is expected to finance its capital expenditures via a combination of its own operating cash flow and external financing.

Long-term debt at the Pinnacle parent level is limited to a $175 million of 5.91% senior notes due February 2011.

Pinnacle's Prime-3 rating for its short-term obligations assumes that the company will manage the amount of commercial paper and other near term obligations outstanding within the limits of its readily available sources of cash, including its committed bank credit facilities.

Rating Outlook

The stable outlook for Pinnacle reflects the nature of APS' predominately regulated cash flows and Moody's view that its improved cash flow financial metrics are likely to be sustainable. The outlook assumes APS' will be reasonably successful in managing its regulatory relationships and that capital expenditures will be financed in a balanced manner with a goal of maintaining or improving Pinnacle's current position of financial strength.

What Could Change the Rating - Up

Pinnacle' rating is not likely to be revised upward in the near-to-medium term. Longer term, if there to be an increase in supportive regulatory treatment at APS resulting in material, timely rate increases, or if there were to be material reductions in costs or leverage such that Moody's could anticipate key financial ratios improving significantly from their current levels, if for example, a ratio of CFO pre -WC / debt could be maintained in the low twenty percent range.

What Could Change the Rating - Down

A downgrade could result if Palo Verde experiences an extended outage and APS is unable to recover, in a timely manner, higher maintenance and purchased power costs, or if APS' regulatory lag for capital spending becomes more pronounced. A downgrade could result if Moody's expects a sustained weakening of financial metrics, if for example, the ratio of CFO pre -WC / debt would remain below the mid-teens for an extended period. A downgrade could also result if there were to be an increase in Pinnacle's consolidated business risk profile; if for example, it were to materially increase its investment in, or its commitments to its more volatile, non-regulated operations, including SunCor.

Rating Factors

Pinnacle West Capital Corporation

609400

Select Key Ratios for Global Regulated Electric Utilities

Rating	Aa	Aa	A	A	Baa	Baa	Ba	Ba
Level of Business Risk	Medium	Low	Medium	Low	Medium	Low	Medium	Low
CFO pre-W/C to Interest (x) [1]	>6	>5	3.5-6.0	3.0-5.7	2.7-5.0	2-4.0	<2.5	<2
CFO pre-W/C to Debt (%) [1]	>30	>22	22-30	12-22	13-25	5-13	<13	<5
CFO pre-W/C - Dividends to Debt (%) [1]	>25	>20	13-25	9-20	8-20	3-10	<10	<3
Total Debt to Book Capitalization (%)	<40	<50	40-60	50-70	50-70	60-75	>60	>70

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

ARIZONA CORPORATION COMMISSION
STAFF'S SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
JULY 31, 2008

Staff Interim 2.59 Net cash flow to capital expenditures. (a) Provide all information related to the portion of its net cash flow to total capital expenditures for 2008 and 2009 that APS has. (b) Please provide estimates of net cash flow to total capital expenditures under the following scenarios, \$115 million of interim rates effective 11/15/08, and assuming respectively that APS were to be granted permanent rates by October 1, 2009 at each of the following: (1) 100% of APS's request \$278; (2) 75% of that permanent rate request; (3) 50% of that permanent rate request; (4) 41% of the permanent rate request; and (4) 25% of the permanent rate request. (c) Please provide estimates of net cash flow to total capital expenditures under the following scenarios, one-half of the \$115 million of interim rates effective 11/15/08, and assuming respectively that APS were to be granted permanent rates by October 1, 2009 at each of the following: (1) 100% of APS's request \$278; (2) 75% of that permanent rate request; (3) 50% of that permanent rate request; (4) 41% of the permanent rate request; and (4) 25% of the permanent rate request. (d) Please provide estimates of net cash flow to total capital expenditures under the following scenarios, none of the \$115 million of interim rates effective 11/15/08, and assuming respectively that APS were to be granted permanent rates by October 1, 2009 at each of the following: (1) 100% of APS's request \$278; (2) 75% of that permanent rate request; (3) 50% of that permanent rate request; (4) 41% of the permanent rate request; and (4) 25% of the permanent rate request. (e) Please include Excel files electronically for the calculations provided in response to parts a-d, above.

Supplemental Response:

As indicated in APS's initial response, APS and Staff agreed that APS would provide six of the scenarios requested. Attached hereto as APS13349 is a summary of the supplemental response, and attached as APS13350 through APS13355 are the detailed calculations of these scenarios in Excel format.

Second Supplemental Response:

Staff requested and APS agreed to provide four more of the scenarios requested. Attached hereto as APS13356 is a summary of all 10 cases APS has provided, and attached as APS13357 through APS13360 are the detailed calculations of the four additional scenarios in Excel format.

Witness: Donald Brandt

Staff Interim Data Request 2.59 and 2.60 - Case Summaries($M)

Case #1 - Staff Interim 2.59 and 2.60
100% of $115M Interim Nov'08, 100% Fuel Incr 10/01/09 (7%), 100% of Non-Fuel Increase (10%)

	2008	2009	2010
Rate Increase			
Fuel Related Increase - 10/01/09 - 7.0%	-	42	193
Non Fuel Related -10/01/09 - Bal of 10.0%	-	60	277
Interim - (11/01/08 if applied) - 100%	16	88	-
Case #1 Rate Increase Revenues- $Ms	16	190	470
APS Earnings	282	336	409
FFO / Adjusted Total Debt	23.3%	20.7%	21.3%
Net Cash Flow as a % of CapEx	72%	65%	75%
APS ROE	8.0%	8.6%	9.7%
APS ACC ROE	8.7%	9.1%	10.8%

Case #3 - Staff Interim 2.59 and 2.60
50% of $115M Interim Nov'08, 100% Fuel Incr 10/01/09 (7%), 100% of Non-Fuel Increase (10%)

	2008	2009	2010
Rate Increase			
Fuel Related Increase - 10/01/09 - 7.0%	-	42	193
Non Fuel Related -10/01/09 - Bal of 10.0%	-	60	277
Interim - (11/01/08 if applied) - 50%	8	44	-
Case #3 Rate Increase Revenues- $Ms	8	146	470
APS Earnings	278	309	406
FFO / Adjusted Total Debt	23.2%	19.9%	21.0%
Net Cash Flow as a % of CapEx	72%	63%	74%
APS ROE	7.9%	7.9%	9.7%
APS ACC ROE	8.5%	8.3%	10.8%

Case #5 - Staff Interim 2.59 and 2.60
No $115M Interim, 100% Fuel Incr 10/01/09 (7%), 100% of Non-Fuel Increase (10%)

	2008	2009	2010
Rate Increase			
Fuel Related Increase - 10/01/09 - 7.0%	-	42	193
Non Fuel Related -10/01/09 - 10.0%	-	60	277
Interim - (11/01/08 if applied) - 0%	-	-	-
Case #5 Rate Increase Revenues- $Ms	-	102	470
APS Earnings	273	282	405
FFO / Adjusted Total Debt	23.0%	19.1%	20.8%
Net Cash Flow as a % of CapEx	71%	60%	74%
APS ROE	7.8%	7.3%	9.7%
APS ACC ROE	8.4%	7.6%	10.8%

Case #2 - Staff Interim 2.59 and 2.60
100% of $115M Interim Nov'08, 100% Fuel Incr 10/01/09 (7%), 50% of Non-Fuel Increase (5%)

	2008	2009	2010
Rate Increase			
Fuel Related Increase - 10/01/09 - 7.0%	-	42	193
Non Fuel Related -10/01/09 - Bal of 5.0%	-	30	139
Interim - (11/01/08 if applied) - 100%	16	88	-
Case #2 Rate Increase Revenues- $Ms	16	160	332
APS Earnings	282	318	322
FFO / Adjusted Total Debt	23.3%	20.2%	18.9%
Net Cash Flow as a % of CapEx	72%	64%	66%
APS ROE	8.0%	8.1%	7.7%
APS ACC ROE	8.7%	8.5%	8.3%

Case #4 - Staff Interim 2.59 and 2.60
50% of $115M Interim Nov'08, 100% Fuel Incr 10/01/09 (7%), 50% of Non-Fuel Increase (5%)

	2008	2009	2010
Rate Increase			
Fuel Related Increase - 10/01/09 - 7.0%	-	42	193
Non Fuel Related -10/01/09 - Bal of 5.0%	-	30	139
Interim - (11/01/08 if applied) - 50%	8	44	-
Case #4 Rate Increase Revenues- $Ms	8	116	332
APS Earnings	278	291	320
FFO / Adjusted Total Debt	23.2%	19.4%	18.7%
Net Cash Flow as a % of CapEx	72%	61%	66%
APS ROE	7.9%	7.5%	7.8%
APS ACC ROE	8.5%	7.8%	8.4%

Case #6 - Staff Interim 2.59 and 2.60
No $115M Interim, 100% Fuel Incr 10/01/09 (7%), 50% of Non-Fuel Increase (5%)

	2008	2009	2010
Rate Increase			
Fuel Related Increase - 10/01/09 - 7.0%	-	42	193
Non Fuel Related -10/01/09 - 5.0%	-	30	139
Interim - (11/01/08 if applied) - 0%	-	-	-
Case #6 Rate Increase Revenues- $Ms	-	72	332
APS Earnings	273	264	319
FFO / Adjusted Total Debt	23.0%	18.7%	18.5%
Net Cash Flow as a % of CapEx	71%	59%	66%
APS ROE	7.8%	6.8%	7.8%
APS ACC ROE	8.4%	7.0%	8.5%

Staff Interim Data Request 2.59 and 2.60 - Case Summaries($M)

#7 - Staff Interim 2.59 and 2.60
of $115M Interim Nov'08, 100% Fuel Incr 10/01/09 (7%), 75% of Non-Fuel Increase (7.5%)

	2008	2009	2010
Rate Increase			
Fuel Related Increase - 10/01/09 - 7.0%	-	42	193
Non Fuel Related -10/01/09 - Bal of 7.5%	-	45	207
Interim - (11/01/08 if applied) - 50%	8	44	-
Case #7 Rate Increase Revenues- $Ms	8	131	400
APS Earnings	278	300	363
FFO / Adjusted Total Debt	23.2%	19.7%	19.8%
Net Cash Flow as a % of CapEx	72%	62%	70%
APS ROE	7.9%	7.7%	8.7%
APS ACC ROE	8.5%	8.0%	9.6%

Case #8 - Staff Interim 2.59 and 2.60
50% of $115M Interim Nov'08, 100% Fuel Incr 10/01/09 (7%), 25% of Non-Fuel Increase (2.5%)

	2008	2009	2010
Rate Increase			
Fuel Related Increase - 10/01/09 - 7.0%	-	42	193
Non Fuel Related -10/01/09 - Bal of 2.5%	-	15	69
Interim - (11/01/08 if applied) - 50%	8	44	-
Case #8 Rate Increase Revenues- $Ms	8	101	262
APS Earnings	278	282	277
FFO / Adjusted Total Debt	23.2%	19.2%	17.6%
Net Cash Flow as a % of CapEx	72%	60%	61%
APS ROE	7.9%	7.2%	6.8%
APS ACC ROE	8.5%	7.5%	7.2%

#9 - Staff Interim 2.59 and 2.60
115M Interim, 100% Fuel Incr 10/01/09 (7%), 75% of Non-Fuel Increase (7.5%)

	2008	2009	2010
Rate Increase			
Fuel Related Increase - 10/01/09 - 7.0%	-	42	193
Non Fuel Related -10/01/09 - 7.5%	-	45	207
Interim - (11/01/08 if applied) - 0%	-	-	-
Case #9 Rate Increase Revenues- $Ms	-	87	400
APS Earnings	273	273	362
FFO / Adjusted Total Debt	23.0%	18.9%	19.7%
Net Cash Flow as a % of CapEx	71%	59%	70%
APS ROE	7.8%	7.0%	8.8%
APS ACC ROE	8.4%	7.3%	9.7%

Case #10 - Staff Interim 2.59 and 2.60
No $115M Interim, 100% Fuel Incr 10/01/09 (7%), 25% of Non-Fuel Increase (2.5%)

	2008	2009	2010
Rate Increase			
Fuel Related Increase - 10/01/09 - 7.0%	-	42	193
Non Fuel Related -10/01/09 - 2.5%	-	15	69
Interim - (11/01/08 if applied) - 0%	-	-	-
Case #10 Rate Increase Revenues- $Ms	-	57	262
APS Earnings	273	255	275
FFO / Adjusted Total Debt	23.0%	18.4%	17.4%
Net Cash Flow as a % of CapEx	71%	58%	61%
APS ROE	7.8%	6.6%	6.8%
APS ACC ROE	8.4%	6.7%	7.2%

ARIZONA CORPORATION COMMISSION
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E-01345A-08-0172
JULY 31, 2008

Staff Interim 2.60 FFO/Debt. (a) Provide all information related to the portion of its FFO/Debt for 2008 and 2009 that APS has. (b) Please provide estimates of FFO/Debt under the following scenarios, $115 million of interim rates effective 11/15/08, and assuming respectively that APS were to be granted permanent rates by October 1, 2009 at each of the following: (1) 100% of APS's request $278; (2) 75% of that permanent rate request; (3) 50% of that permanent rate request; (4) 41% of the permanent rate request; and (4) 25% of the permanent rate request. (c) Please provide estimates of FFO/Debt under the following scenarios, one-half of the $115 million of interim rates effective 11/15/08, and assuming respectively that APS were to be granted permanent rates by October 1, 2009 at each of the following: (1) 100% of APS's request $278; (2) 75% of that permanent rate request; (3) 50% of that permanent rate request; (4) 41% of the permanent rate request; and (4) 25% of the permanent rate request. (d) Please provide estimates of FFO/Debt under the following scenarios, none of the $115 million of interim rates effective 11/15/08, and assuming respectively that APS were to be granted permanent rates by October 1, 2009 at each of the following: (1) 100% of APS's request $278; (2) 75% of that permanent rate request; (3) 50% of that permanent rate request; (4) 41% of the permanent rate request; and (4) 25% of the permanent rate request. (e) Please include Excel files electronically for the calculations provided in response to parts a-d, above.

Supplemental Response:

See APS's supplemental response to Staff Interim 2.59.

Second Supplemental Response:

See APS's second supplemental response to Staff Interim 2.59.

Witness: Donald Brandt

STANDARD & POOR'S

RATINGSDIRECT

U.S. Utilities Ratings Analysis Now Portrayed In The S&P Corporate Ratings Matrix

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U.S. Utilities Ratings Analysis Now Portrayed In The S&P Corporate Ratings Matrix

The electric, gas, and water utility ratings ranking lists published today by Standard & Poor's U.S. Utilities & Infrastructure Ratings practice are categorized under the business risk/financial risk matrix used by the Corporate Ratings group. This is designed to present our rating conclusions in a clear and standardized manner across all corporate sectors. Incorporating utility ratings into a shared framework to communicate the fundamental credit analysis of a company furthers the goals of transparency and comparability in the ratings process. Table 1 shows the matrix.

Table 1

Business Risk/Financial Risk

	Financial Risk Profile				
Business Risk Profile	**Minimal**	**Modest**	**Intermediate**	**Aggressive**	**Highly leveraged**
Excellent	AAA	AA	A	BBB	BB
Strong	AA	A	A-	BBB-	BB-
Satisfactory	A	BBB+	BBB	BB+	B+
Weak	BBB	BBB-	BB+	BB-	B
Vulnerable	BB	B+	B+	B	B-

The utilities rating methodology remains unchanged, and the use of the corporate risk matrix has not resulted in any changes to ratings or outlooks. The same five factors that we analyzed to produce a business risk score in the familiar 10-point scale are used in determining whether a utility possesses an "Excellent," "Strong," "Satisfactory," "Weak," or "Vulnerable" business risk profile:

- Regulation,
- Markets,
- Operations,
- Competitiveness, and
- Management.

Regulated utilities and holding companies that are utility-focused virtually always fall in the upper range ("Excellent" or "Strong") of business risk profiles. The defining characteristics of most utilities--a legally defined service territory generally free of significant competition, the provision of an essential or near-essential service, and the presence of regulators that have an abiding interest in supporting a healthy utility financial profile--underpin the business risk profiles of the electric, gas, and water utilities.

As the matrix concisely illustrates, the business risk profile loosely determines the level of financial risk appropriate for any given rating. Financial risk is analyzed both qualitatively and quantitatively, mainly with financial ratios and other metrics that are calculated after various analytical adjustments are performed on financial statements prepared under GAAP. Financial risk is assessed for utilities using, in part, the indicative ratio ranges in table 2.

Table 2

Financial Risk Indicative Ratios - U.S. Utilities

(Fully adjusted, historically demonstrated, and expected to consistently continue)

	Cash flow		Debt leverage
	(FFO/debt) (%)	(FFO/interest) (x)	(Total debt/capital) (%)
Modest	40 - 60	4.0 - 6.0	25 - 40
Intermediate	25 - 45	3.0 - 4.5	35 - 50
Aggressive	10 - 30	2.0 - 3.5	45 - 60
Highly leveraged	Below 15	2.5 or less	Over 50

The indicative ranges for utilities differ somewhat from the guidelines used for their unregulated counterparts because of several factors that distinguish the financial policy and profile of regulated entities. Utilities tend to finance with long-maturity capital and fixed rates. Financial performance is typically more uniform over time, avoiding the volatility of unregulated industrial entities. Also, utilities fare comparatively well in many of the less-quantitative aspects of financial risk. Financial flexibility is generally quite robust, given good access to capital, ample short-term liquidity, and the like. Utilities that exhibit such favorable credit characteristics will often see ratings based on the more accommodative end of the indicative ratio ranges, especially when the company's business risk profile is solidly within its category. Conversely, a utility that follows an atypical financial policy or manages its balance sheet less conservatively, or falls along the lower end of its business risk designation, would have to demonstrate an ability to achieve financial metrics along the more stringent end of the ratio ranges to reach a given rating.

Note that even after we assign a company a business risk and financial risk, the committee does not arrive by rote at a rating based on the matrix. The matrix is a guide–it is not intended to convey precision in the ratings process or reduce the decision to plotting intersections on a graph. Many small positives and negatives that affect credit quality can lead a committee to a different conclusion than what is indicated in the matrix. Most outcomes will fall within one notch on either side of the indicated rating. Larger exceptions for utilities would typically involve the influence of related unregulated entities or extraordinary disruptions in the regulatory environment.

We will use the matrix, the ranking list, and individual company reports to communicate the relative position of a company within its business risk peer group and the other factors that produce the ratings.

The McGraw-Hill Companies

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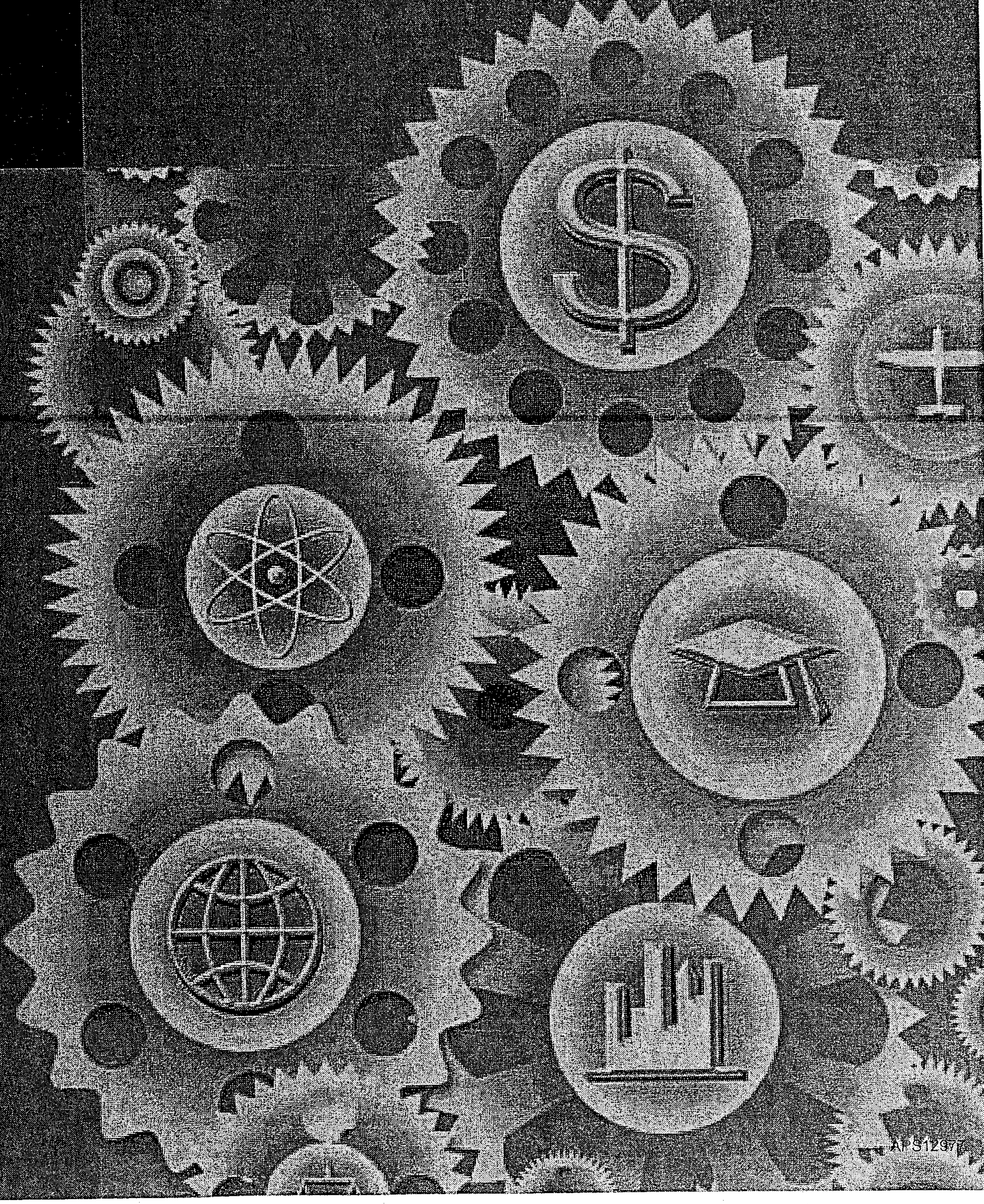
Corporate Ratings Criteria

2008



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Corporate Ratings Criteria

2008

For the most complete and up-to-date ratings criteria, please visit
Standard & Poor's Web site at www.corporatecriteria.standardandpoors.com.

To Our Clients

Standard & Poor's Ratings Services' criteria publications represent our endeavor to convey the thought processes and methodologies employed in determining Standard & Poor's ratings. They describe both the quantitative and qualitative aspects of the analysis. We believe our rating product has the most value if users appreciate all that has gone into producing the letter symbols.

Bear in mind, however, that a rating is, in the end, an opinion. The rating assignment is as much an art as it is a science.

Solomon B. Samson
Chief Rating Officer, Corporate Ratings

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Contents

Standard & Poor's Ratings—And Their Role In The Financial Markets

Standard & Poor's Ratings Services traces its history back to 1860. It currently is the leading credit rating organization and a major publisher of financial information and research services on U.S. and foreign corporate and municipal debt obligations. We now rate many trillions of dollars worth of bonds and other financial obligations of obligors in more than 50 countries. We rate and monitor developments pertaining to these issues and issuers from an office network based in 22 world financial centers.

Standard & Poor's was an independent, publicly owned corporation until 1966, when all of its common stock was acquired by McGraw-Hill Inc., a major publishing company. Standard & Poor's is now a business unit of McGraw-Hill. In matters of credit analysis and ratings, Standard & Poor's Credit Market Services operates entirely independently of McGraw-Hill. Other units of Standard & Poor's provide investment, financial, and trading information, data, and analyses—including on equity securities—but operate separately from the ratings group. Standard & Poor's operates with no government mandate and is independent of any investment banking company, bank, or similar organization.

What Is Standard & Poor's?

We are an organization of professionals that provides analytical services—high-quality, objective, value-added analytical information—to the world's financial markets.

We operate under the core values of:

- Independence;
- Objectivity;
- Credibility; and
- Disclosure.

Our recognition as a rating agency ultimately depends on investors' willingness to accept our judgment. We believe it is important that all of our ratings users understand how we arrive at those ratings, and we regularly publish ratings research and detailed reports on ratings criteria and methodology.

We began rating the debt of corporate and government issuers decades ago. Our credit rating criteria and methodology have grown in sophistication to keep pace with a more dynamic world, and the introduction of new financial products. For example, Standard & Poor's was the first major rating agency to assess the credit quality of, and assign credit ratings to, the claims-paying ability of insurance companies (1971); financial guarantees (1971); mortgage-backed bonds (1975);

mutual funds (1983); asset-backed securities (1985); and secured loan recovery (2003). Over the years, these credit ratings have achieved wide investor acceptance as easily usable tools for differentiating credit quality.

The Rating Process Has Many Facets

Many of the practices described here are governed by specific statements of policy, which can be located on sandp.com/Ratings/Form NRSRO/Exhibits 2, 3, and 7.

Standard & Poor's provides ratings only when there is adequate information available to form a credible opinion, and only after applicable quantitative, qualitative, and legal analyses are performed. The analytical framework is divided into several categories to ensure that salient qualitative and quantitative issues are considered. For example, regarding industrial companies, the qualitative categories are oriented to business analysis, such as the company's competitiveness within its industry and the caliber of management; the quantitative categories relate to financial risk.

The rating process is not limited to an examination of various financial measures. Proper assessment of credit quality for an industrial company includes a thorough review of business fundamentals, including industry prospects for growth and vulnerability to technological change, labor unrest, or regulatory actions. (Other sectors emphasize factors that are especially relevant to entities in that sector. For example, public finance ratings involve an evaluation of the basic underlying economic strength of the public entity, as well as the effectiveness of the governing process to address problems. In financial institutions, the reputation of the bank or company may have an impact on the future financial performance and the institution's ability to repay its obligations.)

We assemble a team of analysts with appropriate expertise to review information pertinent to the rating. A lead analyst is responsible for conducting the analysis and coordinating the rating process. Members of the analytical team meet with the rated entity's management to review, in detail, key factors that could affect on the rating, including operating and financial plans and management policies. The meeting also helps analysts develop the qualitative assessment of management itself, an important factor in many rating decisions.

Following this review and discussion, a rating committee meeting is convened. At the meeting, the committee discusses the lead analyst's recommendation and the facts and expectations supporting the rating. Finally, the voting members of the committee vote on the recommendation.

The issuer subsequently is notified of the rating and the major considerations supporting it. A rating can be appealed prior to its publication—if meaningful new or additional information is to be presented by the issuer. Obviously, there is no guarantee that any new information will alter the rating committee's decision.

Once a final rating is assigned, it is disseminated to the public via RatingsDirect, S&P.com, and the news media, together with the rationale and other commentary.

In the U.S., Standard & Poor's assigns and publishes its ratings irrespective of issuer request, if the financing is a public deal. In the case of private transactions, the company has publication rights. In most markets outside the U.S., ratings are assigned only on request, so the company can choose to make its rating public or to keep it confidential. (Confidential ratings are disclosed by us only to parties designated by the rated entity.)

Surveillance And Review Are Ongoing

All ratings are monitored, including continual review of new financial or economic information. Our surveillance is ongoing, meaning we staying abreast of all current developments. Moreover, it is routine to schedule annual review meetings with management, even in the absence of the issuance of new obligations or apparent reason to question the extant rating or outlook. These meetings enable analysts to discuss potential problem areas and be apprised of any changes in the issuer's plans.

As a result of the surveillance process, it is sometimes necessary to reassess the rating or outlook. The lead analyst initiates a review, conducted in a similar fashion to the initial rating assignment process. In the interim, we place the ratings on CreditWatch, if we believe the likelihood of a rating change is sufficiently high. The review entails a comprehensive analysis—including, if warranted, a meeting with management—and a presentation to a rating committee. The rating committee evaluates the circumstances, arrives at decisions on ratings and outlooks, notifies the issuer, and entertains an appeal, if one is made (and meets our policy for accepting appeals). After this process, all ratings and outlooks—whether changed or affirmed—are announced.

Issuers' Use Of Ratings

It is common for companies to structure financing transactions to reflect rating criteria so they qualify for higher ratings. However, the actual structuring of a given issue is the exclusive function and responsibility of an issuer and its advisors. We develop and publish criteria as new financing alternatives are proposed. We will also react to a proposed financing, apply and interpret criteria for a type of issue, and outline the rating implications for the benefit of an issuer, underwriter, bond counsel, or financial advisor—but we do not function as an investment banker or financial advisor. Adopting such a role ultimately would impair the objectivity and credibility that are vital to our continued performance as an independent rating agency. Our guidance also is sought on sundry credit quality issues that might affect the rating opinion. For example, companies solicit our view on hybrid preferred stock, the monetization of assets, or other innovative financing techniques before putting these into practice. Nor is it uncommon for debt issuers to undertake specific and sometimes significant actions for the sake of maintaining their ratings. For example, one large company faced a downgrade of its 'A-1' commercial paper rating because of a growing component of short-term, floating-rate debt. To keep its rating, the company chose to restructure its debt maturity schedule in a way consistent with our view of what was consistent with the profile of an 'A' rated credit.

Some companies go one step further, incorporating specific rating objectives as corporate goals. Indeed, earning an 'A' rating, or at least an investment-grade rating, affords companies a measure of flexibility and may be worthwhile as part of an overall financial strategy. Beyond that, we do not encourage companies to manage themselves with an eye toward a specific rating. The more appropriate approach is to operate for the good of the business as management sees it and to let the rating follow. Ironically, managing for a very high rating can sometimes be inconsistent with the company's ultimate best interests, if it means being overly conservative and forgoing opportunities.

Several Types Of Credit Ratings

A Standard & Poor's credit rating is our opinion of the general creditworthiness of an obligor (issuer credit rating/corporate credit rating), or the credit risk associated with a particular debt security or other financial obligation (issue rating).

A rating does not constitute a recommendation to purchase, sell, or hold a particular security. In addition, a rating does not comment on the liquidity of the rated instrument—or any other element affecting suitability of an investment for a particular investor (including currency, interest rate, and prepayment risk).

Credit ratings are based on information furnished by the obligors or obtained by us from other sources we consider reliable. Although we look at information we receive with a critical eye, we do not perform any kind of audit (of financial statements or transactions) in connection with any credit rating—and may, on occasion, rely on unaudited financial information. Credit ratings may be changed, suspended, or withdrawn as a result of changes in, or unavailability of, such information.

We maintain separate and well-established rating scales for long-term and short-term instruments. (A separate scale for preferred stock was integrated with the debt scale in February 1999. There is an additional scale exclusively for medium-term municipal notes.)

In non-'AAA' transfer and convertibility (T&C) zones, we assign both foreign- and local-currency issuer credit ratings. We also have introduced several national scale ratings, applicable in specific countries, and recovery ratings, which opine on loss given default.

Long-term credit ratings are divided into several categories, ranging from 'AAA'—reflecting the strongest credit quality—to 'D', reflecting the lowest. Long-term ratings from 'AA' to 'CCC' may be modified by the addition of a plus or minus sign to show relative standing within the major rating categories.

A short-term credit rating is an assessment of an issuer's credit quality with respect to an instrument considered short term in the relevant market. Short-term ratings range from 'A-1', for the highest-quality obligations, to 'D', for the lowest. The 'A-1' rating may also be modified by a plus sign to distinguish the strongest credits in that category.

Issuer Credit Ratings

We provide issuer credit ratings—an opinion of the obligor's overall capacity and willingness to meet its financial obligations as they come due—whether rated or not. Default on any of these leads to an issuer rating of 'D' or 'SD' *(see Definitions, page 11)*.

However, if payment is withheld due to disputes (as may pertain to operating or lease obligations), we do not deem this to be a default. Our issuer credit rating is not specific to any particular financial obligation, because it does not take into account the specific nature or provisions of any particular obligation. Such ratings do not take into account recovery prospects or statutory or regulatory preferences, nor do they take into account the creditworthiness of guarantors, insurers, or other forms of credit enhancement that may pertain to a specific obligation. (However, when we believe that support from a third party—such as an affiliate or government—would benefit the issuer in ways that make the overall risk of default more remote, such support is factored into the rating.)

Counterparty ratings, corporate credit ratings, and sovereign credit ratings are all forms of issuer credit ratings. Because a corporate credit rating provides an overall assessment of a company's creditworthiness, it is used for a variety of financial and commercial purposes, such as negotiating long-term leases or minimizing the need for a letter of credit for vendors. If the credit rating is not assigned in conjunction with a rated public financing, the company can choose to make its rating public or to keep it confidential.

Credit ratings can be either long or short term. Short-term ratings are assigned to those obligations considered short term in the relevant market. In the U.S., for example, that means obligations with an original maturity of no more than 365 days, including commercial paper. Commercial paper ratings pertain to the program established to sell these notes. There is limited review of individual notes. Nonetheless, such program ratings characterize the notes as "rated paper."

Short-term ratings also are used to indicate the creditworthiness of an obligor with respect to put features on long-term obligations. The result is a dual rating, in which the short-term rating addresses the put feature in addition to the usual long-term rating. Medium-term notes (MTNs) are assigned long-term ratings. A rating is assigned to the MTN program and, subsequently, to individual notes, as they are identified—and as applicable (in terms of tenor, seniority, and currency).

Issue-Specific Credit Ratings

Our issue credit rating is a current opinion of the credit risk pertaining to a specific financial obligation, a specific class of financial obligations, or a specific financial program. This opinion reflects, where applicable, the creditworthiness of guarantors, insurers, or other forms of credit enhancement on the obligation, and takes into account statutory and regulatory preferences. On a global basis, Standard & Poor's issue credit rating criteria have long identified the added country-risk factors that give external debt a higher default probability than domestic obligations. (In 1992, we revised our criteria to define external rather than domestic obligations by currency instead of by market of issuance. This led to the adoption of the local currency/foreign currency nomenclatures for issue credit ratings.) Because rating coverage now has expanded to a growing range of emerging-market countries, and because Organisation for Economic Co-operation and Development (OECD)-based companies increasingly have expanded to emerging markets, the analysis of political, economic, and monetary risk factors are even more important.

Definitions

Our long-term issue ratings ('AAA' through 'D') are assigned to notes, note programs, certificate of deposit programs, bank loans, bonds and debentures; shelf registrations (preliminary), equipment trust certificates, and preferred stock and other hybrid securities. Debt types include secured, senior unsecured, subordinated, junior subordinated, and deferrable payment debt.

Short-term issue ratings ('A-1+' through 'D') apply to commercial paper programs and put bonds. (The rating type is determined by the initial tenor; once a long-term rating is applied, the approach of the maturity does not lead to re-rating with a short-term rating.)

Issue and issuer credit ratings use the identical symbols, but the definitions do not completely correspond to each other: Issuer ratings—and short-term issue ratings—reflect only the risk of default, but long-term issue ratings also incorporate a view of loss given default (either via a specific recovery analysis or by reflecting relative position of the obligation in the event of bankruptcy, reorganization, or other arrangement under the laws of bankruptcy and other laws affecting creditors' rights.)

Junior obligations typically are rated lower than the issuer credit rating, to reflect the lower priority in bankruptcy, as noted above. Debt that provides good prospects for ultimate recovery, such as well-secured debt, is rated higher than the issuer credit rating.

Recovery ratings ('1+' through '6') are our opinion of a specific issue's prospects regarding loss given default. We generally assign these ratings to the debt of speculative-grade companies. Wherever we assign a recovery rating, that rating forms the basis for notching the issue credit rating relative to the issuer rating.

Long-term ratings definitions

'AAA': An obligation rated 'AAA' has the highest rating we assign. The obligor's capacity to meet its financial commitment on the obligation is extremely strong.

'AA': An obligation rated 'AA' differs from the highest-rated obligations only to a small degree. The obligor's capacity to meet its financial commitment on the obligation is very strong.

'A': An obligation rated 'A' is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rated categories. However, the obligor's capacity to meet its financial commitment on the obligation is still strong.

'BBB': An obligation rated 'BBB' exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation.

Obligations rated 'BB', 'B', 'CCC', 'CC', and 'C' are regarded as having significant speculative characteristics. 'BB' indicates the least degree of speculation, and 'C' the highest. While such obligations likely will have some quality and protective characteristics, these may be outweighed by large uncertainties or major exposure to adverse conditions.

'BB': An obligation rated 'BB' is less vulnerable to nonpayment than other speculative issues. However, it faces major ongoing uncertainties or exposure to adverse business, financial, or economic conditions that could lead to the obligor's inadequate capacity to meet its financial commitment on the obligation.

'B': An obligation rated 'B' is more vulnerable to nonpayment than obligations rated 'BB', but the obligor currently has the capacity to meet its financial commitment on the obligation. Adverse business, financial, or economic conditions likely will impair the obligor's capacity or willingness to meet its financial commitment on the obligation.

'CCC': An obligation rated 'CCC' is vulnerable to nonpayment within one year, and depends on favorable business, financial, and economic conditions for the obligor to meet its financial commitment on the obligation.

In the event of adverse business, financial, or economic conditions, the obligor is unlikely to have the capacity to meet its financial commitment on the obligation.

'CC': An obligation rated 'CC' currently is highly vulnerable to nonpayment.

'C': The 'C' rating is also used when a bankruptcy petition has been filed or similar action has been taken but payments on this obligation are being continued. 'C' is also used for a preferred stock that is in arrears (as well as for junior debt of issuers rated 'CCC-' and 'CC').

'D': Default; 'SD': Selective default. The 'D' and 'SD' ratings, unlike other ratings, are not prospective; rather, they are used only when a default actually has occurred—not when default is only expected.

Standard & Poor's changes ratings to 'D':

- On the day an interest and/or principal payment is due and is not paid. An exception is made if the instrument provides for a grace period and we believe a payment will be made within that period, in which case the rating can be maintained;
- Upon voluntary bankruptcy filing or similar action. (An exception is made for a specific issue if we expect debt-service payments will continue to be made on that issue.) In the absence of a payment default or bankruptcy filing, a technical default (e.g., covenant violation) is not sufficient for assigning a 'D' rating;
- Upon completion of a distressed exchange offer, whereby some or all of an issue is either repurchased for an amount of cash or replaced by other securities having a total value that clearly is less than par (even though the offer is well in excess of the security's current market price); or,
- In the case of ratings on preferred stock or deferrable payment securities, upon nonpayment of the dividend or deferral of the interest payment.

With respect to issuer credit ratings (i.e., corporate credit ratings, counterparty ratings, and sovereign ratings), failure to pay any financial obligation—rated or unrated—leads to either a 'D' or 'SD' rating. Ordinarily, an issuer's distress leads to general default, and the rating is 'D'. 'SD' is assigned when an issuer can be expected to default selectively, i.e., continue to pay certain issues or classes of obligations while not paying others. This fact pattern normally is associated with sovereign government defaults. In the corporate context, selective default might apply when a company conducts a distressed or coercive exchange with respect to one or some issues, while intending to honor its obligations regarding other issues. (In fact, it is not unusual for a company to launch such an offer precisely with such a strategy—to restructure part of its debt to keep the company solvent.) Nonpayment of a financial obligation subject to a bona fide commercial dispute or a missed preferred stock dividend does not cause the issuer credit rating to be changed.

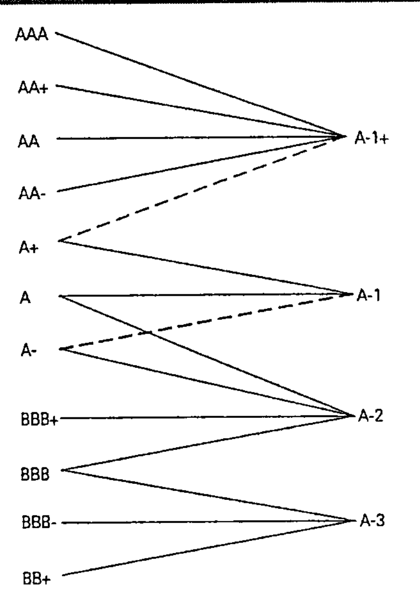
Plus (+) or minus (-): The ratings from 'AA' to 'CCC' may be modified by the addition of a plus or minus sign to show relative standing within the major rating categories. In 1994, we introduced a symbol to be added to an issue credit rating when the instrument could have significant non-credit risk. The 'r' was added to such instruments as interest-only strips, inverse floaters, and instruments that pay non-fixed amounts at maturity, e.g., amounts based the value of a particular equity or a currency or stock index. The 'r' was intended to alert investors to non-credit risks and emphasizes that an issue credit rating addressed only the credit quality of the obligation; it was discontinued in July 2000.

Short-term ratings definitions

'A-1': A short-term obligation rated 'A-1' is in the highest category we rate. The obligor's capacity to meet its financial commitment on the obligation is strong. Within this category, certain obligations are designated with a plus sign (+). This indicates that the obligor's capacity to meet its financial commitment on these obligations is extremely strong.

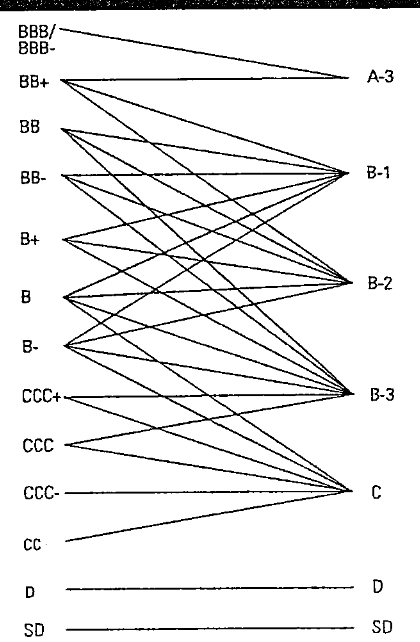
'A-2': A short-term obligation rated 'A-2' is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rating categories. However, the obligor's capacity to meet its financial commitment on the obligation is satisfactory.

Chart 1 **Correlation Of Short-Term Investment-Grade Ratings With Long-Term Corp Credit Ratings***



*Dotted lines indicate combinations that are highly unusual

Chart 2 **Correlation Of Short-Term Speculative-Grade Ratings With Long-Term Corp Credit Ratings**



'A-3': A short-term obligation rated 'A-3' exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation.

'B': A short-term obligation rated 'B' has, in our view, significant speculative characteristics. The obligor currently has the capacity to meet its financial commitment on the obligation; however, it faces major ongoing uncertainties that could lead to inadequate capacity to meet its financial commitment on the obligation. We expanded the 'B' short-term rating category in 2004 by dividing it into 'B-1', 'B-2', and 'B-3'.

'C': A short-term obligation rated 'C' currently is vulnerable to nonpayment and depends on favorable business, financial, and economic conditions for the obligor to meet its financial commitment on the obligation

'D': The same as the long-term rating definition for 'D'.

Investment-grade, short-term ratings are highly correlated with long-term ratings *(see Commercial Paper chapter of this book)*. Speculative-grade short-term ratings reflect less constraint regarding linkage to long-term ratings.

Investment And Speculative Grades

The term "investment grade" originally was used by various regulatory bodies to connote obligations eligible for investment by institutions such as banks, insurance companies, and savings and loan associations. Over time, it gained widespread use throughout the investment community. Issues rated in our four highest categories—'AAA', 'AA', 'A', and 'BBB'—generally are recognized as investment grade. Debt rated 'BB' or below generally is considered "speculative grade." (The term "junk bond" is merely an irreverent expression for this category of more risky debt; "high-grade" and "high-yield" debt are common terms, as well.) Nomenclature aside, we take no view as to which securities are worthy of investment, because an investor with a particular risk preference may appropriately invest in securities that are not investment grade.

Ratings continue as a factor in many regulations, both in the U.S. and abroad, notably in Europe and Japan. For example, the SEC requires investment-grade status in order to register debt on Form-3, which, in turn, is one way to offer debt via a Rule 415 shelf registration. The Federal Reserve Board allows members of the Federal Reserve System to invest in securities rated in the four highest categories, just as the Federal Home Loan Bank System permits federally chartered savings and loan associations to invest in corporate debt with those ratings, and the Department of Labor allows pension funds to invest in commercial paper rated in one of the three highest categories. In similar fashion, California regulates investments of municipalities and county treasurers; Illinois limits collateral acceptable for public deposits; and Vermont restricts investments of insurers and banks. The New York and Philadelphia stock exchanges fix margin requirements for mortgage securities depending on their ratings, and the securities haircut for commercial paper, debt securities, and preferred stock that determines net capital requirements is also a function of the ratings assigned.

Currency

We devised two types or ratings in order to comment on the risks associated with payment in currencies other than the entity's home country. Such payments typically are made outside the company's home country, so the risks encompass both transfer and convertibility.

- A local currency rating is our current opinion of an obligor's overall capacity to generate sufficient local currency resources to meet its financial obligations (both foreign and local currency), absent the risk of direct sovereign intervention that may constrain payment of foreign currency debt. Depending on the location of a company's operations, such intervention could relate to more than one government. Local currency credit ratings are provided on our global scale or on separate national scales, and may be either issuer or specific issue credit ratings. Country or economic risk considerations factored into local-currency ratings include the impact of government policies on the obligor's business and financial environment, including factors such as the exchange rate, interest rates, inflation, labor market conditions, taxation, regulation, and infrastructure. However, the opinion does not address transfer and other risks related to direct sovereign intervention to prevent the timely servicing of cross-border obligations.
- A foreign currency credit rating is our current opinion of an obligor's overall capacity to meet all financial obligations—including its foreign-currency-denominated financial obligations. It may take be either an issuer or an issue credit rating. As in the case of local currency credit ratings, a foreign currency credit opinion on our global scale is based on the obligor's individual credit characteristics, including the influence of country or economic risk factors. However, unlike local currency ratings, a foreign currency credit rating includes transfer and other risks related to sovereign actions that

Table 1 **Cumulative Default Rates 1981–2006 (%)**

Year	AAA	AA	A	BBB	BB	B	CCC/C
1	0.0	0.0	0.1	0.2	1.1	5.0	26.3
2	0.0	0.1	0.2	0.7	3.1	10.9	34.7
3	0.1	0.1	0.3	1.2	5.6	15.9	40.0
4	0.2	0.2	0.5	1.9	8.0	19.8	43.2
5	0.3	0.3	0.7	2.6	10.1	22.6	46.2
10	0.7	0.9	1.9	5.4	17.5	30.4	51.8
15	0.8	1.3	2.8	7.9	20.8	35.0	54.6

Source: S&P Annual 2006 Global Default Study.

may directly affect access to the foreign exchange needed for timely servicing of the rated obligation. Transfer and other direct sovereign risks addressed in such ratings include the likelihood of foreign-exchange controls and the imposition of other restrictions on the repayment of foreign debt.

(See Analytical Methodology/Country Risk section of this book for a discussion of the relationship of these ratings to ratings on the pertinent sovereign.)

National Scale Ratings

We produce national scale ratings in a number of countries across throughout the world. These ratings are expressed with the traditional letter symbols, but the rating definitions do not conform to those employed for the global scale. The rating definitions of each national scale and its correlation to global scale ratings are unique, so there is no basis for comparability across national scales.

CreditWatch Listings And Rating Outlooks

Our ratings evaluate default risk over the life of a debt issue, incorporating an assessment of all future events to the extent they are known or can be anticipated. But we also recognize the potential for future performance to differ from initial expectations. Rating outlooks and CreditWatch listings address this possibility by focusing on the scenarios that could result in a rating change. Ratings (both issuer and issue ratings) appear on CreditWatch when an event or deviation from an expected trend has occurred or is expected such that there is a significant chance (roughly 50% or more) of requiring a rating change, and additional information is necessary to take a rating action. For example, an issue is placed under such special surveillance as the result of mergers, recapitalizations, regulatory actions, or unanticipated operating developments.

We attempt to resolve CreditWatch reviews within 90 days, unless the outcome of a specific event is still pending. A listing does not mean a rating change is inevitable; however, in some cases, it is certain that a rating change will occur, and only the magnitude of the change is unclear. In such situations, we immediately lower the corporate credit rating to the highest-conceivable outcome, or upgrade it to the lowest-conceivable outcome, while also listing the rating on CreditWatch for potential additional actions. In those instances—and generally, whenever possible—we comment on the range of alternative ratings. An issuer cannot automatically appeal a CreditWatch listing, but our analysts are sensitive to their concerns and the fairness of the process.

Rating changes also can occur without the issue appearing on CreditWatch beforehand. In fact, if all necessary information is available, ratings should immediately be changed to reflect the changed circumstances; there should be no delay merely to signal via a CreditWatch listing that a ratings change is to occur.

A rating outlook is assigned to all long-term debt issuers and assesses the potential for an issuer rating change. Outlooks have a longer time frame than CreditWatch listings—typically, two years for investment-grade entities, and one year for speculative-grade entities—and incorporate trends or risks with less certain implications for credit quality. (Ratings that are listed on CreditWatch, by definition, have no assigned outlook.)

A negative, developing, or positive outlook is not necessarily a precursor of a rating change or a CreditWatch listing. CreditWatch designations and outlooks may be positive, meaning the rating may be raised, or negative, meaning it may be lowered. Developing is used for those unusual situations in which future events are so unclear that the rating could be raised or lowered. A stable outlook is assigned when ratings likely will not be changed within the applicable timeframe, but it should not be confused with expected stability of the company's financial performance. ■

Our Rating Process

Most corporations approach us to request a rating prior to the sale or registration of a debt issue. That way, first-time issuers can receive an indication of what rating to expect. Issuers with rated debt outstanding also want to know in advance what affect issuing additional debt will have on the ratings we already have assigned. (As a matter of policy, in the U.S., we assign and publish ratings for all public corporate debt issues over $100 million—with or without a request from the issuer. In these cases, we contact the issuer to elicit its cooperation.)

The analysts with the greatest relevant industry/country expertise are assigned to evaluate the credit and commence surveillance of the company. Our analysts generally concentrate on one or two industries, covering the entire spectrum of credits within those industries. Such specialization allows the analysts to accumulate expertise and competitive information better than if junk-bond issuers were followed separately from high-grade issuers. While one analyst takes the lead in following a given issuer and typically handles day-to-day contact, a team of experienced analysts—including a back-up analyst—is always assigned to the rating relationship with each issuer.

Meeting With Management

A meeting with corporate management is an integral part of our rating process. The purpose is to review in detail the company's key operating and financial plans, management policies, and other credit factors that have an impact on the rating. Management meetings are critical in helping to reach a balanced assessment of a company's circumstances and prospects.

Participation

The company typically is represented by its chief financial officer. The chief executive officer usually participates when strategic issues are reviewed (usually the case at the initial rating assignment). Operating executives often present detailed information regarding business segments. Outside advisors may be helpful in preparing an effective presentation. We neither encourage nor discourage their use: It is entirely up to management whether advisors assist in the preparation for meetings, and whether they attend the meetings.

Scheduling

Management meetings usually are scheduled at least several weeks in advance, to assure mutual availability of the appropriate participants and to allow adequate preparation time for our analysts. In addition, if a rating is being sought for a pending issuance, it is to the issuer's advantage to allow about three weeks following a meeting for us to complete the review process. More time may be needed in certain cases, if, for example, extensive review of documentation is necessary. However, where special circumstances exist and a quick turnaround is needed, we endeavor to meet the requirements of the marketplace.

Facility Tours

Touring major facilities can be very helpful for us to understand a company's business. However, it generally is not critical in assigning a rating to a given company. Considering the time constraints that typically arise in the initial rating exercise, arranging facility tours may not be feasible. As discussed below, such tours may well be a useful part of the subsequent surveillance process.

Preparing For Meetings

Corporate management should feel free to contact its designated Standard & Poor's credit analyst for guidance in advance of the meeting regarding the particular areas that will be emphasized in the analytic process. Published ratings criteria, as well as industry commentary and articles on peer companies, may also help management appreciate the analytic perspective.

Providing detailed, written lists of questions tends to constrain spontaneity and artificially limit the scope of the meeting. Therefore, some of our practices prefer not to do so, while other practices endeavor in other ways to avoid such outcomes.

We request that the company submit background materials well in advance of the meeting, (ideally, several sets), including:

- five years of audited annual financial statements;
- the last several interim financial statements;
- narrative descriptions of operations and products; and
- if available, a draft registration statement or offering memorandum, or equivalent.

Apart from company-specific material, relevant industry information also is useful. While not mandatory, written presentations by management often help provide a framework for the discussion. Such presentations typically mirror the format of the meeting discussion, as outlined below. Where a written presentation is prepared, it is particularly useful for our team to review it in advance of the meeting.

There is no need to try to anticipate all questions that might arise. If additional information is necessary to clarify specific points, it can be provided subsequent to the meeting. In any case, our credit analysts generally will have follow-up questions that arise as the information covered at the management meeting is further analyzed.

Confidentiality

A substantial portion of the information set forth in company presentations is highly sensitive and is provided by the issuer to us solely for the purpose of arriving at ratings. Such information is kept strictly confidential by the ratings group, on a need-to-know basis. (Obviously, if information is known to us or comes to be known from other sources, the company cannot expect us to treat this information confidentially.) It is not to be used for any other purpose, nor by any third party, including other Standard & Poor's units. Standard & Poor's maintains a "Chinese Wall" between its rating activities and its equity information services. Even if a public rating is subsequently assigned, any rationales or other information we publish about the company will refer only to publicly available corporate information. In the same vein, if we change a rating or outlook based on confidential information received, we will take pains to avoid disclosing that information in our published materials.

Conduct Of Meeting

In a typical meeting with issuer management, we typically address:

- industry environment and prospects;

- an overview of major business segments, including operating statistics and comparisons with competitors and industry norms;
- financial polices and financial performance goals;
- distinctive accounting practices;
- projections, including income and cash flow statements and balance sheets, together with the underlying market and operating assumptions;
- capital spending plans; and
- financing alternatives and contingency plans.

It should be understood that our ratings are not based on the issuer's financial projections or management's view of what the future may hold. Rather, ratings are based on our assessment of the company's prospects. However, management's financial projections are a valuable tool in the rating process, because they indicate management's plans, how management assesses the company's challenges, and how it intends to deal with problems. Projections also depict the company's financial strategy in terms of anticipated reliance on internal cash flow or outside funds, and they help articulate management's financial objectives and policies.

Management meetings with companies new to the rating process typically last two to four hours, or longer if the company's operations are particularly complex. If the issuer is domiciled in a country new to ratings or participates in a new industry, more time is usually required. When, in addition, there are major accounting issues to be covered, meetings can last a full day or two.

Short, formal presentations by management are useful to introduce areas for discussion. We prefer meetings to be interactive and largely informal, with ample time allowed for questions and responses. (At management meetings, as at all other times, we welcome the company's questions regarding our procedures, methodology, and analytical criteria.)

Rating Committee

A committee is always convened to assign a new issuer rating. Rating committees normally consist of five to seven voting members, and a chairperson reviews the suitability of the committee participants.

A presentation is made by the lead analyst to the rating committee, which has been provided in advance with appropriate financial statistics and comparative analysis. The presentation follows the methodology as outlined in the methodology section below. It includes analysis of the company's business and its operating environment, evaluation of its strategic and financial management, accounting aspects, and financial analysis. When rating a specific issue, there is additional discussion of the proposed issue and terms of the indenture.

Once the ratings are determined, the company is notified, and told of the major supporting considerations. We allow the issuer to respond to the rating decision prior to its publication by presenting new or additional data. We entertain appeals in the interest of having available the most information possible and, thereby, the most accurate ratings. In the case of a decision to change an extant rating, any appeal must be conducted as expeditiously as possible, i.e., within a day or two. The committee reconvenes to consider the new information.

After notifying the company, the rating is disseminated via the media, or released to the company for dissemination in the case of private placements or corporate credit ratings.

To maintain the integrity and objectivity of our rating process, our internal deliberations and the identities of those who sat on a rating committee are kept confidential, and not disclosed to the issuer.

Surveillance

Corporate ratings on publicly distributed issues are monitored for at least one year. The company can then elect to pay us to continue surveillance. Ratings assigned at the company's request have the option of surveillance, or being on a "point-in-time" basis.

Surveillance is performed by the same industry analysts that work on the assignment of the ratings. In fact, we strive to provide continuity of the lead analyst and a portion of the relevant rating committee (some members do rotate, though, to allow for fresh perspectives, and the lead analyst role must rotate after five years). To facilitate surveillance, companies put the lead analyst on mailing lists to receive interim and annual financial statements, press releases, and bank documents, including compliance certificates. The lead analyst is in periodic contact with the company to discuss ongoing performance and developments. Where these vary significantly from expectations, or where a major, new financing transaction is planned, an update management meeting is appropriate. We also encourage companies to discuss hypothetically—again, in strict confidence—transactions that perhaps are only being contemplated (e.g., acquisitions, new financings), and, where practicable, we endeavor to provide frank feedback about the potential ratings implications of such transactions.

In any event, management meetings routinely are scheduled at least annually. These meetings enable analysts to keep abreast of management's view of current developments, discuss business units that have performed differently from original expectations, and be apprised of changes in plans. As with initial management meetings, we willingly provide guidance in advance regarding areas we believe warrant emphasis: There generally is no need to dwell on basic information covered at the initial meeting. Apart from discussing revised projections, it is helpful to revisit the prior projections and to discuss how actual performance varied, and why.

A significant proportion of meetings with company officials takes place on the company's premises. There are several reasons: to facilitate increased exposure to management personnel—particularly at the operating level; obtain a first-hand view of critical facilities; and achieve a better understanding of the company by spending more time reviewing the business units in depth. While we actively encourage meetings on company premises, time and scheduling constraints on both sides dictate that arrangements for these meetings be made some time in advance.

Because the staff is organized by specialty, credit analysts typically meet each year with most major companies in their assigned area to discuss the industry outlook, business strategy, and financial forecasts and policies. This way, competitors' forecasts of market demand can be compared with one another, and we can assess implications of competitors' strategies for the entire industry. Our analysts can judge management's relative optimism regarding market growth and relative aggressiveness in approaching the marketplace.

Importantly, the analyst compares business strategies and financial plans over time and seeks to understand how and why they changed. This exercise provides insights regarding management's abilities with respect to forecasting and implementing plans. By meeting with different managements over the course of a year, and the same management year after year, analysts can distinguish between managements with thoughtful, realistic agendas and those with wishful approaches.

Management credibility is achieved to the extent the record demonstrates that a company's actions are consistent with its plans and objectives. Once earned, credibility helps support continuity of a particular rating level, because we can rely on management to do what it says to maintain and/or restore creditworthiness when faced with financial stress or strategic challenge. Once lost, credibility is difficult to restore. The rating process benefits from the unique perspective on credibility gained by extensive evaluation of management plans and financial forecasts over many years.

Rating Changes

As a result of the surveillance process, it sometimes becomes apparent that changing conditions require reconsideration of the outstanding rating. When this occurs, the analyst undertakes a preliminary review, which, after internal deliberation, may lead to a CreditWatch listing. This is followed by a comprehensive analysis, communication with management, and a presentation to the rating committee. The rating committee evaluates the matter, arrives at a rating decision, and notifies the company—after which we publish the rating changes, if any, and the new outlook. The process is exactly the same as the rating of a new issue. Reflecting this surveillance, the timing of rating changes depends neither on the sale of new debt issues nor on our internal schedule for reviews. ■

Analytical Methodology

Our rating methodology is based on fundamental analysis. Our model has evolved over time to reflect greater complexity and volatility facing companies. Current ratings analysis puts much greater emphasis on cash flow adequacy and liquidity than in the past. Our profitability analysis was part of our financial risk review, but we now emphasize its role as part of our business risk and competitive assessment.

Overview

Over the past five or six years, we have paid significantly more attention to accounting considerations and corporate governance. While management's risk orientation has always been a critical part of our rating decisions, there is a more complex corporate landscape now—including the availability of ever more complicated securities and transactions. Accordingly, we need to drill deeper into management practices and policies, including a range of issues, from ownership to board independence to off-balance sheet stratagems.

Business risk/financial risk matrix

We strive for transparency around the rating process. However, it is critical to realize—and it should be apparent—that the ratings process cannot be reduced to a cookbook approach: Ratings incorporate many subjective judgments, and remain as much an art as a science.

Our corporate analytical methodology organizes the analytical process according to a common framework, and it divides the task into several categories so that all salient issues are considered. The first categories involve fundamental business analysis; the financial analysis categories follow. (Credit ratings often are identified with financial analysis—especially ratios. And we publish ratio statistics and benchmarks both for sectors and individual companies. But ratings analysis starts with the assessment of the business and competitive profile of the company. Two companies with identical financial metrics are rated very differently, to the extent that their business challenges and prospects differ.)

We developed the matrix in table 2 to make explicit the rating outcomes that are typical for various business risk/financial risk combinations. The table illustrates the relationship of business and financial risk profiles to the issuer credit rating. The following illustrates how the tables can be used to better understand our rating conclusions.

The hypothetical case of company ABC

Company ABC is deemed to have a satisfactory business risk profile, typical of a low investment-grade industrial issuer. If its financial risk were "intermediate", the expected rating outcome should be 'BBB'.

ABC's ratios of cash flow to debt (35%) and debt leverage (total debt to EBITDA of 2.5x) are indeed characteristic of intermediate financial risk. (The assessment of financial risk really is not so simple: It encompasses financial policies and risk tolerance, volatility and risks to future performance, several perspectives on cash flow adequacy—including free cash flow and the degree of flexibility regarding capital expenditures, and various measures of liquidity—including coverage of short-term maturities.)

Company ABC can aspire to an upgrade to the 'A' category by reducing its debt burden to the point that cash flow to debt is more than 60% and debt leverage is only 1.5x. Conversely, ABC may choose to become more financially aggressive—perhaps it decides to reward shareholders by borrowing to repurchase its stock. The company can expect to be rated in the 'BB' category if its cash flow to debt ratio is 20% and debt leverage remains at 4x—and there is a commitment to keeping its finances at these levels.

The rating matrix is a guideline, not written in stone

The rating matrix is not meant to be precise. There can always be small positives and negatives that would lead to a notch higher or lower than the typical outcome.

Moreover, there will always be exceptions—cases that do not fit neatly into this analytical framework. For example, liquidity concerns or litigation could pose overarching risks. Also, the matrix does not address the lowest rungs of the credit spectrum (i.e., the 'CCC' category and lower). These ratings, by definition, reflect some impending crisis or extraordinary vulnerability, and the balanced approach that underlies the matrix framework just does not lend itself to such situations.

Corporate Credit Analysis Categories

The categories underlying our business and financial risk assessments are:

Business Risk

- Country risk
- Industry factors
- Competitive position
- Profitability/Peer group comparisons

Table 2 Business Risk/Financial Risk

	—Financial risk profile—				
Business risk profile	**Minimal**	**Modest**	**Intermediate**	**Aggressive**	**Highly Leveraged**
Excellent	AAA	AA	A	BBB	BB
Strong	AA	A	A-	BBB-	BB-
Satisfactory	A	BBB+	BBB	BB+	B+
Weak	BBB	BBB-	BB+	BB-	B
Vulnerable	BB	B+	B+	B	B-
Financial risk indicative ratios*	**Minimal**	**Modest**	**Intermediate**	**Aggressive**	**Highly Leveraged**
Cash flow (Funds from operations/Debt) (%)	Over 60	45–60	30–45	15–30	Below 15
Debt leverage (Total debt/Capital) (%)	Below 25	25–35	35–45	45–55	Over 55
Debt/EBITDA (x)	<1.4	1.4–2.0	2.0–3.0	3.0–4.5	>4.5

*Fully adjusted, historically demonstrated, and expected to continue consistently.

Financial risk

- Governance/Risk tolerance/Financial policies
- Accounting
- Cash flow adequacy
- Capital structure/Asset protection
- Liquidity/Short-term factors

Note that we do not have any predetermined weights for these categories. The significance of specific factors varies from situation to situation.

Business risk considerations

Country risk. The operating environment in the particular country—including, importantly, any sovereign-related stress—can have an overwhelming impact upon company creditworthiness, both direct and indirect. Sovereign credit ratings suggest general risk faced by local entities, but they may not fully capture risk applicable to the private sector. As a result, when rating corporate or infrastructure companies or projects, we look beyond the sovereign ratings to evaluate the specific economic or country risk that may impact the entity's creditworthiness. Such economic or country risk pertains to the impact of government policies upon the obligor's business and financial environment, and a company's ability to insulate itself from these risks.

Industry factors. All rating analyses incorporate an assessment of the company's business environment. The degree of operating risk facing a company almost always depends on the dynamics of the industry in which it participates. Our industry analysis focuses on the strength of industry prospects, as well as the competitive factors affecting that industry.

The many factors assessed include industry prospects for growth, stability, or decline, and the pattern of business cycles. It is critical, for example, to determine vulnerability to technological change, labor unrest, regulatory interference, or changes in the supply/demand balance. Our knowledge of the investment plans of the major players in a given industry offers a unique vantage point with respect to the future industry's profile.

The industry risk assessment sets the stage for analyzing specific company risk factors/keys to success and establishing the priority of these factors in the overall evaluation. For example, if technology is a critical competitive factor, R&D prowess is stressed. If the industry produces a commodity, cost of production is of major importance.

Still, for any particular company, one or more factors can hold special significance, even if that factor is not common to the industry. For example, the fact that a company has only one major production facility normally is regarded as an area of vulnerability. Similarly, reliance on one product creates risk, even if the product is highly successful (e.g., a pharmaceutical company with only one blockbuster drug that is subject to competition and patent expiration).

Competitive position. Competitive position represents a critical input in assessing a company's level of business risk in our analysis, and can often have a significant impact on the debt rating for an issuer. To determine a given issuer's competitive position, we look at key factors pertinent to the specific industry. A key factor for a pharmaceutical company, for example, might be research and development, whereas marketing would be a particularly important consideration for a consumer products company.

Company size and diversification often plays role. While we have no minimum size criterion for any given rating level, company size tends to be significantly correlated to rating levels. This is because larger companies often benefit from economies of scale and/or diversification, translating into a stronger competitive position. Small companies are, almost by definition, more concentrated in terms of product, number of customers, and geography. To the extent that markets and regional economies change, a broader scope of business affords protection.

Small companies are sometimes touted for their greater growth potential. However, fast growth often is subject to poor execution (even if the idea is well conceived) and can also tempt a company into over-ambitiousness, which could involve added risk.

Management evaluation. Management is assessed for its role in determining operational success and also for its risk tolerance. The first aspect is incorporated in the business risk analysis; the second is weighed as a financial policy factor.

Subjective judgments help determine each aspect of management evaluation. Opinions formed during the meetings with senior management are as important as management's track record. While a track record may seem to offer a more objective basis for evaluation, it often is difficult to determine how results should be attributed to management's skills.

Management plans and policies are judged for their realism. How they are implemented determines the view of management consistency and credibility. Stated policies often are not followed, and a rating may reflect skepticism until management has established credibility. Credibility can become a critical issue when a company is faced with stress or restructuring, and we must decide whether to rely on management to carry out plans for restoring creditworthiness.

Profitability/Peer group comparisons. Profit potential is a critical determinant of credit protection. A company that generates higher operating margins and returns on capital has a greater ability to generate equity capital internally, attract capital externally, and withstand business adversity. Earnings power ultimately attests to the value of the company's assets, as well.

Moreover, conclusions about profitability also serve as a good sanity check on our assessment of business risk: A company's profit performance offers a litmus test of its fundamental health and competitive position. In this regard, comparing peer companies on key profit metrics is most meaningful.

Financial risk considerations

Having evaluated the issuer's operating environment and competitive position, the analysis proceeds to several financial categories. To reiterate, the company's business risk profile determines the level of financial risk appropriate for any rating category. Financial risk is portrayed largely through quantitative means, particularly by using financial ratios. Several analytical adjustments typically are required to calculate ratios for an individual company *(see Encyclopedia of Analytical Adjustments, below)*. Cross-border comparisons require additional care, given the differences in accounting conventions and local financial systems.

Financial policy. We attach great importance to management's philosophies and policies involving financial risk. A surprising number of companies have not given this question serious thought, much less reached strong conclusions. For many others, debt leverage (calculated without any adjustment to reported figures) is the only focal point of such policy considerations. More sophisticated business managers have thoughtful policies that recognize cash flow parameters, the interplay between business and financial risk, and the need to adjust financial data to reflect different needs and perspectives.

Even those companies that have set goals may not have the wherewithal, discipline, or management commitment to achieve these objectives. Leverage goals, for example, need to be viewed in the context of an issuer's past record and the financial dynamics affecting the business.

Accounting characteristics and information risk. Financial statements and related disclosures serve as our primary source of information regarding the financial condition and financial performance of industrial and utility companies. The analysis of financial statements begins with a review of accounting characteristics. The purpose is to determine whether ratios and statistics derived from the statements can be used appropriately to measure a company's performance and position relative to both its direct peer group and the larger universe of corporate issuers. The rating process is, in part, one of comparisons, so it is important to have a common frame of reference.

Analytical adjustments are made to better portray reality and to level the differences among companies—although it rarely is possible to completely recast a company's financial statements. Even where the ability to adjust is limited, it is important to at least have some notion of the extent to which different financial measures are overstated or understated.

Apart from their importance to the quantitative aspects of the analysis, conclusions regarding accounting characteristics and financial transparency can also influence qualitative aspects of the analysis, such as the assessment of management.

Cash flow adequacy. Interest or principal payments cannot be serviced out of earnings, which is just an accounting concept; payment has to be made with cash. Although there usually is a strong relationship between cash flow and profitability, many transactions and accounting entries affect one and not the other. Analysis of cash flow patterns can reveal a level of debt-servicing capability that is either stronger or weaker than might be apparent from earnings.

The analysis often focuses on levels of funds from operations (FFO), but we play close attention to working capital swings, capital spending requirements, and shareholder distributions to complete the picture with respect to cash flow adequacy.

Cash flow analysis is usually the single most critical aspect of credit rating decisions. It takes on added importance for speculative-grade issuers. While companies with investment-grade ratings generally have ready access to external financing to cover temporary cash shortfalls, speculative-grade issuers lack this degree of flexibility and have fewer alternatives to internally generated cash for servicing debt.

Capital structure and asset protection. A review of an issuer's capital structure represents an important part of our financial review. The review encompasses both the level and mix of debt employed (i.e., fixed/variable rate, maturity, currency, secured/unsecured). This analysis helps us determine a company's financial flexibility, and how leveraged it is. Of course, when we look at leverage, our analysis goes beyond reported debt on the balance sheet and includes such items as leases, pension and retiree medical liabilities, guarantees, and contingent liabilities.

In addition, a company's asset mix is a critical determinant of the appropriate leverage for a given level of risk. Assets with stable cash flows or market values justify greater use of debt financing than those with clouded marketability. Accordingly, we believe it is critical to analyze each type of business and asset class in its own right. While the Financial Accounting Standards Board (FASB) and International Accounting Standards (IAS) now require consolidation of nonhomogenous business units, we analyze each separately.

Liquidity/short-term factors. Sundry considerations that do not fit in other categories are examined here. The potential impact of contingencies is considered, along with the company's contingency plans. These include serious legal problems, lack of insurance coverage, or restrictive covenants in loan agreements that place the company at the mercy of its bankers. Access to various capital markets, affiliations with other entities, and the ability to sell assets are important factors in determining a company's options under stress.

Debt maturity schedules are scrutinized. Flexibility can be jeopardized when an issuer is overly reliant on bank borrowings or commercial paper. Issuing commercial paper without adequate backup facilities is a big negative.

As going concerns, companies should not be expected to repay debt by liquidating operations. Clearly, there is little benefit in selling natural resource properties or manufacturing facilities if they must be replaced in a few years. Nonetheless, the ability to generate cash through asset disposals enhances a company's financial flexibility.

Country Risk

Country risk—the risk of doing business in a particular country—is a critical component of many ratings, particularly for companies in emerging markets. The large number of corporate defaults in Argentina during the 2001-2002 crisis was related to a combination of macroeconomic factors, such as severe currency depreciation and weak economic activity, and government actions such as the 'pesification' (conversion to pesos from foreign currency) of financial obligations, utility tariffs, and most other dollar-denominated contracts at an unfavorable exchange rate from a creditor's perspective.

Country risk differs from sovereign credit risk—the risk of the sovereign defaulting on its commercial debt obligations. Country risk is often correlated with sovereign creditworthiness, but not always.

Depending on the industry sector or individual company's financial strength, a company may be better or less able to withstand macroeconomic shocks or other country-related risks. For instance, several—but not all—Brazilian exporters performed well during 2002 despite a severe credit crunch in the marketplace, given government reluctance to interfere with export financing. Commercial banks and state development banks continued to provide lines of credit to major exporters, even though the sovereign suffered credit stress. Most Russian companies continued to perform and to service external, export-backed debt in 1998-1999 when the sovereign was in default.

On the other hand, strengthening credit quality of the sovereign state does not necessarily improve the business environment—or the relevant country risk. For example, while Russia's sovereign credit quality has been improving, the operating environment remains risky. All ratings on Russian companies factor in uncertainty about enforcement of regulatory and legal norms and the still-weak corporate governance environment.

Certain industries tend to be more affected by sovereign issues than others. Banks and utilities are greatly affected by the regulatory framework and by the general condition of the economy. On the opposite end of the spectrum are export-oriented companies, which are less affected by local economic conditions, and generally benefit from currency depreciation. Nevertheless, even exporters are exposed to country risk. For instance, they are subject to local rules on labor and domestic input sourcing, and could suffer a disruption in financial market access because of sovereign-related investor perceptions. Resource nationalism can also make export-oriented commodity industries more likely targets of selective sovereign intervention.

Exposure to country risk may even differ on a company-by-company basis. For instance, in Russia, the large oil and gas producers may each be subject to different risks of government interference.

Government-related companies generally enjoy some government support, but face general country risks as well. While selective sovereign intervention is hardly an issue for them, in terms of outright expropriation, they are still subject to the country's tax and regulatory risks, infrastructure constraints, or exchange rate movements. There are plenty of examples in which the sovereign has induced the government-owned entities to reduce capital investment budgets, increase the tax burden, or pay extraordinary dividends when economic pressures have risen.

Country risk methodology and interaction with the sovereign rating

The main sovereign and industry-related risks affecting and sometimes constraining the credit quality of companies in a certain jurisdiction include various economic, financial, regulatory, and industry-related risks that can affect day-to-day operations, long-term investment decisions, and, of course, payment capacity.

We divide the main country risk factors that could affect the private sector into two categories: Economic/political and industry risks.

Economic risks:

- growth prospects of a country;
- its business cycle;
- political factors influencing the business environment;
- current and projected inflation levels;
- foreign exchange risks affecting the flow of imports, exports, and the balance of payments;
- the payment system and the strength and depth of the banking system;
- interest rates and spreads;
- the depth and liquidity of the local capital markets; and
- access to the cross-border markets for commercial or financial transactions.

Industry-related risks:

- labor market constraints or incentives;
- the strength and political direction of labor unions;
- labor cost and strike experience;
- condition of general infrastructure in the country—with potential constraints on water supply, cost of electricity, and price and availability of oil and gas;
- poor transportation services in roads, ports, and airports;
- accounting and reporting transparency in the country;

- federal and state government legal systems;
- regulatory risk for utilities, banks, and other entities under regulation;
- existence or potential for heavy taxation; and
- corruption-related risks affecting day-to-day operations.

Past experience

The main country risk factors that have affected financial performance and caused corporate defaults in the past are the following:

- Currency mismatch on operations and financial obligations combined with sharp local currency depreciation;
- Price controls combined with drastic raw material increases;
- Sudden contraction of liquidity, combined with a general weakening of the financial system and a possible freezing of bank deposits;
- Large increases in the cost of funds by financial intermediaries, if available;
- Delayed payments from domestic customers, including sovereigns themselves or sovereign-owned entities;
- Hikes in export tariffs or taxes;
- Prolonged labor strikes with excessive demands;
- Unfriendly change in regulations;
- GDP contraction and reduced domestic demand for several months or years;
- Sovereign restrictions on access to foreign exchange needed for debt service; and
- Forced conversion of foreign currency-denominated obligations into local currency.

Ratings above the sovereign

Under our methodology, ratings on a company may exceed those on the sovereign, if we expect it would continue to perform and fulfill its financial obligations, even during a sovereign local and/or foreign currency default scenario. The company must demonstrate that it is significantly sheltered from sovereign and country risk factors, based on past experience and probable scenarios. Where such potential exists, we would perform additional sovereign and country risk stress scenarios as part of the rating analysis.

In addition, ratings above those on the sovereign are possible where there is strong implicit or explicit support from a highly-rated parent in another jurisdiction, and/or there is significant cash-flow diversity derived from operations in several countries.

Foreign currency ratings of an entity would be usually capped by the transfer and convertibility (T&C) assessment for a given country—ordinarily, higher than the sovereign foreign-currency rating. *(See "Ratings Above The Sovereign: Foreign Currency Rating Criteria Update," published Nov. 3, 2005, on RatingsDirect, the real time Web-based source for Standard & Poor's credit ratings, research, and risk analysis. Assessments of T&C risk are published on a monthly basis for all rated sovereigns.)* Nevertheless, a company's foreign currency ratings can exceed the T&C assessment in instances of: very strong credit metrics and business prospects, as projected even through a sovereign default scenario; strong incentives to service foreign debt (links to global trading system); or a projected ability to generate enough foreign currency cash flow to comfortably cover foreign currency outflows.

As of 2007, the foreign currency ratings of 68 entities in 21 countries exceeded the sovereign rating of the country of domicile. *(See "Transfer And Convertibility Assessment History Since November 2005" published June 7, 2007, on RatingsDirect.)* Only a handful, however, exceeded the T&C assessment.

Industry Risk

Industry risk analysis sets the stage for company-specific analysis. The goal is to develop a robust understanding of the company's external business and operating environment. Industry analysis focuses on the industry prospects, as well as identifying the competitive factors, risks, and challenges affecting participants in that industry. Once key industry and country risk considerations are identified, the credit analysis process proceeds to a second phase—company-specific analysis.

Industry characteristics—and the mix of opportunities and risks they represent—include the sector's growth and profit potential, degree of cyclicality, ease of entry, nature and degree of competition, capital intensity, operational and cost structure, regulation, and technology. Companies best-positioned to take advantage of these key industry drivers—or to mitigate associated risks more effectively, possess a competitive advantage—and a stronger business risk profile.

Evaluating an industry's risk profile

While characteristics pertinent to credit risk across industries broadly are similar, the impact of these factors can vary significantly between industries. Table 3 highlights how a common set of industry characteristics/metrics can be applied to identifying the relative credit impact of key industry factors across some major industries in the U.S.

Some industries are more highly affected by national factors than others. The nature and impact of key characteristics can vary markedly between countries for a given industry. Utilities, telecom, and retail tend to be more affected by national characteristics. By contrast, oil & gas, chemicals, and technology sectors are more global in nature, as national factors tend to be less influential.

An example of country-specific influences: Telecom

While the telecom industry recently has been a primary driver of globalization, and the technology platforms and connectivity provided by telecommunication companies form the underpinnings of the global network for voice, data video, and Internet services, it does not have a uniform global credit profile. A few leading operators have diversified internationally by building networks in multiple regions and countries, although none can be said to be global. A major impediment to the creation of truly global players is that many governments view the industry as being of national strategic importance; so, as in the case of utilities, barriers to cross border/global expansion and diversification often are material. The high cost of cross-border entry includes availability and expense of government-sanctioned frequencies and licenses, network-construction capital expense, and, in emerging markets, often the requirement to share profits and management decisions with local partners. The degree of competition in telecom is in many countries a direct function of government policy and regulation, as well as other factors, such as population and business density. National markets with the higher telecom credit risk tend to be those with a high degree of competition, where growth prospects are limited by market maturity, and government and regulatory policy or actions have spurred competition, and historically been inconsistent: The U.K. is an example of one such market. Conversely, in markets with lower levels of competition

Table 3 **Key Industry Characteristics And Drivers Of Credit Risk**

Credit risk impact: High (H); Medium (M); Low (L)

Risk factor	Cyclicality	Competition	Capital intensity	Technology risk	Regulatory/ government	Energy sensitivity
Industry	H	H	H	L	M/H	H
Airlines (U.S.)	H	H	H	M	M	H
Autos*	H	H	H	M	M	M
Auto suppliers*	H	H	M	H	L	L/M
High technology*	H	H	H	M	M/H	H
Mining*	H	H	H	L	M	L
Chemicals (bulk)*	H	H	H	L	M	H
Hotels*	H	H	H	L	L	M
Shipping*	H	H	H	L	L	M
Competitive power*	H	H	M	L	H	H
Telecoms (Europe)	M	H	H	H	H	L

*Global.

(often because of government policies and regulations that aim to support price levels and profit margins, and create surplus cash generation to fund infrastructure spending by incumbents), and growth prospects are high, the sector credit-risk profile can be much more favorable. A prime example of the latter market is China. Key ratings metrics, such as operating margins, EBITDA coverage, and leverage ratios for China's dominant incumbent wireline and wireless companies reflect this advantage, and are among the strongest of any rated telecom. However, in the case of China, our ratings on these companies are constrained by sovereign/country-risk considerations. Markets where competition is limited by government policy are obviously susceptible over time to policy changes leading to greater market liberalization. While the possibility of a major policy U-turn in China currently appears low, it is essential that any likelihood of changes that would foster greater competition be factored into the analysis in markets where there is a high degree of government protection.

High-risk industries

Certain sectors historically have experienced higher default rates and downward transition behavior. This can be linked to key high-risk industry characteristics. Ratings within such industries tend to cluster, because competitive differentiation is often hard to achieve and financing needs are relatively similar.

Still, it is critical not to paint an entire industry with the same brush. In fact, the stress of many companies in a particular industry can result from the superior execution and performance of their rivals. Such competitive divergence should be mirrored in a bifurcated ratings profile for that industry.

Factors with a high level of impact on credit risk are cyclicality, degree of competition, capital intensity, technological risk, regulation/deregulation, and energy cost sensitivity.

Mature industries that are very competitive often have long-established companies with inflexible/legacy cost structures (arising from labor, pension, and/or environmental issues, among others). Industries in this category include autos, airlines, and integrated steel.

Cyclicality

Industry cycles result not only from fluctuating demand, but, importantly, also from swings in supply capacity. (Such addition of new capacity often occurs in response to cyclical upswings in demand.) Overbuilding of production capacity exacerbates competitive and earnings pressure, especially in the event of a downturn in demand (examples of this dynamic: bulk chemicals and shipping).

A company's business can be so impaired during a downturn that it runs out of funds—or its competitive position may be permanently altered. In the extreme, a company will not survive a cyclical downturn to participate in the upturn. So, all else equal, companies subject to cyclicality are rated lower than non-cyclical companies.

We attempt to avoid assigning high ratings to a company at its peak of cyclical prosperity, if that performance level is expected to be only temporary. Similarly, we may not lower ratings to reflect weakening performance because of cyclical factors, if the downturn is likely to be only temporary or there are good prospects for management to respond to the changed circumstances.

It is not that ratings are not adjusted with the phases of a cycle: Rather, the range of the ratings would not fully mirror the amplitude of the company's cyclical highs or lows, given the expectation that a cyclical pattern will persist. The expectation of change from the current performance level—for better or worse—tempers any rating action.

We do not—and cannot—aim to "rate through the cycle" entirely. Rating through the cycle requires an ability to predict the cyclical pattern—usually extremely difficult to do. The phases of a cycle probably will be longer or shorter, or steeper or less severe, than just repetitions of earlier cycles. Interaction of cycles from different parts of the globe and the convergence of secular and cyclical forces are further complications.

Moreover, even predictable cycles can affect individual companies in ways that have a lasting impact on credit quality. As noted, a company may fail during the cyclical downturn. Conversely, a company may accumulate enough cash in the upturn to mitigate the risks of the next downturn.

Furthermore, investor sentiment about cyclical credits may fluctuate over the course of a cycle, with important ramifications for financial flexibility. Whatever our own views about the long-term staying power of a given company, the degree of public confidence in the company's financial viability determines its access to capital markets, bank credit, and even trade credit—for better or worse. Accordingly, the psychology and the perceptions of capital providers must be taken into account.

Sensitivity to cyclical factors—and ratings stability—also varies considerably along the rating spectrum. As the credit quality of a company becomes increasingly marginal, the nature and timing of near-term changes in market conditions are more likely to mean the difference between survival and failure. A cyclical downturn may involve the threat of default before the opportunity to participate in the upturn that may follow. In such situations, cyclical fluctuations usually will lead directly to rating changes—possibly even several rating changes in a relatively short period. Conversely, a cyclical upturn may give companies a breather that may warrant a modest upgrade or two from those very low levels.

In contrast, companies viewed as having strong fundamentals (i.e., those enjoying investment-grade ratings) are unlikely to see significant rating changes because of factors deemed to be cyclical, unless the cycle is either substantially different from that expected, or the company's performance is somehow exceptional relative to that expected.

(Rating stability for a company throughout a cycle also presumes consistency in business strategy and financial policy. In reality, management psychology is often strongly influenced by the course of a cycle. For example, in the midst of a prolonged, highly favorable cyclical rebound, a given management's resolve to pursue a conservative growth strategy and financial policy may be weakened. Shifts in management psychology may affect not just individual companies, but entire industries. Favorable market conditions may spur industry-wide acquisition activity or capacity expansion.)

Capital intensity

To the degree that a business is capital intensive, return/break-even horizons are often further out, because of the need to invest heavily in fixed assets/production capacity. Operating leverage/capacity utilization adds to the risk profile.

Sectors that are both capital intensive and have a high degree of competition (e.g., autos, shipping, forest products, and metals & mining) are especially sensitive to the need for high capacity utilization. Nonetheless, capital-intensive sectors often have a high propensity to over-expand capacity in growth periods, leading to surplus capacity, intense price competition, and eroding margins. Perhaps ironically, such companies also tend to have above-average financial risk, as financing needs often are substantial and long.

Rapid change

Industries undergoing rapid change because of technological innovation and/or deregulation tend to have higher levels of industry risk. Barriers to entry can be substantially reduced, allowing an entry to new competitors that may not be burdened by legacy business models, technologies, and the cost structures of incumbents.

There is greater potential for industry peers sorting themselves into winners and losers—as companies pursue different business models/strategies. The quality of management is particularly important in such industries.

Risks in maturing or declining industries

Maturing economic and demographic environment can lead to market saturation (e.g., anemic growth rates in Western Europe and Japan for autos and steel). Technological change may spur substitution (fixed-wireline phones by mobile/wireless; traditional media advertising by Internet ads; pharmaceutical medications by bio-medications; and print media/news by Internet news services). New business models can lead to disintermediation (local retailers by mega retailers, and traditional airlines by low-cost carriers).

Stagnant or declining revenues require cost-reduction to maintain profitability. Product differentiation also tends to be difficult in maturing industry environments, as there is a high degree of correlation between industry maturity and product commoditization (brands do afford companies protection from commoditization in some sectors). Industry consolidation often is challenging—both for the companies making the acquisitions—and those left to compete with them.

Risks in rapidly growing, immature industries

The promise of new technologies and new business models—while a threat to the existing companies—is not a panacea for the innovators either (e.g., Internet and dot.com companies). High-growth industries, particularly those driven by technological change, tend to have long investment breakeven horizons, especially if they are capital intensive. Their early periods are associated with losses and negative cash flow.

Unproven commercial viability of a new technology and/or business model also make them poor candidates for obtaining credit. New industries normally are funded in their early phases through venture capital (e.g., biotechnology).

Some high-technology/high-growth industries are viewed as having economic and political importance to national governments, which may protect them from market competition in an attempt to stimulate their development (as noted with China's telecoms). Barriers to entry erected by governments in the form of licensing, franchise auctioning, and laws barring competition and acquisition by nonsanctioned entities are used to provide a protected environment. However, as these industries mature, governments open them up to varying degrees of competition by allowing new entrants or removing monopolistic privileges incumbents had previously enjoyed. Once deregulated, such industries normally become much riskier from a credit perspective, because increased competition erodes industry profit margins.

"Old" industries can become rejuvenated in emerging markets

Not all industry high-growth opportunities are created by new technology or business models. Currently, the rapid industrialization of developing countries (notably China and India) is creating growth industries for mature products—including auto manufacturing, capital goods, and steel. In addition, countries seeking to attract foreign participants offer protected environments and/or assistance and inducements.

Such status can prove tempting for foreign companies establishing operations, but early foreign entrants often find it hard to maintain adequate profitability once tax holidays end and/or new entrants are in place. (Again, China offers a good example: the government's decision to allow the entrance of additional Western, Japanese, and Korean auto manufacturers has created a high degree of competition with rapidly declining profit margins, despite very rapid market and sales growth.)

Potentially onerous government regulations, policies, and requirements, as well tolerance of illicit activity—such as proprietary technology transfers/piracy, are additional risk elements that need to be considered.

Competitive Position

Competitive positioning is the cornerstone of business risk analysis. While the industry environment, whether favorable or unfavorable, will strongly influence the business risk, differences in competitive positioning can justify substantial differences in credit standing among industry players. A strong business profile score can only be achieved through a very competitive position. Such status supports revenue and cash flow stability—and generally goes in tandem with superior profitability measures. A comparatively weak competitive position—even in the most favorable industry environment—is unlikely to result in a solid credit standing.

Sustainability is key

The sustainability and trend of a competitive position are critical rating factors. Sustainability of competitive advantage is often determined by cost leadership or product differentiation. A broader evaluation would look at:

- Product positioning (quality, pricing) and brand reputation;
- Market shares, the installed customer base, and geographic coverage;

- Distribution capabilities;
- Customer relationships;
- Technology/manufacturing capabilities; and
- Meaningful barriers to entry, such as transportation, capital or technology intensiveness, and regulation.

The assessment of these factors must, of course, be forward looking; we use historical data only to the extent that they provide insight into future trends.

Several other factors also are critical in determining the strength and sustainability of a company's competitive position. Vertical integration, for instance, often enables a stronger competitive position—although not necessarily higher returns on capital employed—protection of the customer base, and pricing power, as well as better ability to adjust to technology developments. That said, it is of utmost importance for a company to have the strongest grip on that part of the value chain that comprises the highest value added.

Market share analysis can be a critical component, but only when weighed in the context of industry dynamics

In noncommodity sectors, market share analysis often provides important insight into a company's competitive strength. A large share, however, is not always synonymous with a competitive advantage or with industry dominance. If an industry has a number of similarly large participants, none may have a particular advantage or disadvantage. (This is the case of the mature U.K. mobile telephony market, which, despite having four competitors with roughly similar large market shares, is characterized by intense competition, yielding relatively low margins for all market participants.) Even duopolies (such as the aircraft manufacturing industry) do not necessarily ensure high and stable margins. Highly fragmented industries (such as transportation—with airlines being a good example) may lack pricing leadership potential altogether. These examples underline the limits of market share analysis without understanding the industry context.

Global industries typically are characterized by gradual market consolidation and the risk of product commoditization; only large, cost-efficient players with vast research and distribution capabilities are able to sustain or reinforce their business positions and profitability.

In contrast, companies operating in local industries may benefit from transportation barriers, long-term regulatory advantages, or a locally large installed asset or customer base. This is sometimes the case for food retailers, which can enjoy all these advantages, helping them achieve relatively solid business risk profiles, based on entrenched and well-managed local positions.

Comparing mature and fast-growing markets

An emerging or fast-growing market offers considerable growth prospects, but competitive positions in such markets are likely to be more volatile. Companies may reap substantial benefits over a relatively short period of time but find it difficult to manage over the long haul. (Moreover, fast-growth companies often tend to retain high-risk financial policies as they aggressively pursue ever more ambitious objectives, thereby limiting potential credit quality.) The promise of small companies can fade very quickly on growth-related risks, including management's experience and resources to enter new markets, or to integrate acquired companies.

A mature market, although perhaps not appealing from an earnings growth standpoint and possibly exposed to risks of price commoditization or revenue decline, can mean greater protection for market shares. Large companies in mature markets have substantial staying power. Their sizable staff, vast array of disposable assets, and often-significant restructuring potential can positively influence their fates.

Generally, we would therefore favor a solid, established position in a mature, consolidated industry, which would have greater ability to offer predictable revenue and earnings streams, and to protect a company's capacity to service its debt over the long term.

Diversification can enhance the business risk profile

Having a diverse range of products, customers, and/or suppliers helps cushion a company against adversity. Geographic spread can also afford some protection against adverse changes in regional markets and economies, to the extent that the markets for a company's products or services are sufficiently uncorrelated.

When a company operates in more than one business, we analyze each segment separately. We then form a composite from these building blocks, weighing each element according to its importance within the overall organization. (Determination of importance can vary; we often use earnings contribution, especially if segment cash flow data are unavailable.)

Diversification that includes a good competitive position in several industry segments is then considered as a positive credit factor. The business profile of a company solidly positioned in an array of cash-generative businesses with different industrial cycles is stronger in terms of credit quality than each of the best-ranked stand alone competitors.

However, we generally are cautious with respect to the benefits of business diversification related to weaker competitive positions or activities exposed to a very difficult industry environment.

Global conglomerates generally achieve some of the highest ratings among corporate issuers. Impressive geographic spreads, balanced exposure to cyclical industries and economic conditions, and often very sizable market shares in consolidated, well-protected markets are common features of some of the world's largest conglomerates, such as U.S.-based General Electric Co. (AAA/Stable/A-1+).

Size and ratings end up being highly correlated

While we have no minimum size criterion for any given rating level, size and ratings do end up being correlated, given that size often provides a measure of diversification, and/or affects competitive positioning.

It is relative—not absolute—size that is crucial in determining market position, extent of diversification, and financial flexibility. Small companies also can enjoy the competitive advantages that accompany a dominant market position, although such a situation is not common. In this sense, sheer mass is not important; demonstrable market advantage is.

Accordingly, small or modest size generally is a negative rating factor if there is significant divergence in size and market shares between the market leaders and smaller players. Nevertheless, small and midsize enterprises can survive and perform satisfactorily in industries dominated by companies with large market shares, provided they can build defendable market positions in niche segments of the industry. German sports car designer and manufacturer Porsche AG (not rated) has successfully defended and expanded its strong position in luxury sports cars with respect to competitors owned by large car manufacturers.

As noted, large companies in highly fragmented industries may find it difficult to exert influence over pricing; instead, all industry players are exposed to intense competition. This is the case in the semiconductor industry, for example (with the exception, perhaps, of the microprocessor segment), where none of the large players has demonstrated a long-term ability to differentiate themselves in a highly competitive environment. The transportation and logistics industries are other good examples.

Large size also is often positively correlated with low cost. Economies of scale in purchasing, manufacturing, and distribution can provide large companies with better cash flow characteristics, which is of particular importance at the downside of the cycle. In some cases, like forest products, group size may not be the most critical aspect of cost advantage; rather, the size of the individual production units—in particular the size of the machines—is critical.

Also, small companies are, almost by definition, more concentrated in terms of product, number of customers, and geography. In effect, they lack certain elements of diversification that can benefit larger companies. To the extent that market and regional economies change, a broader business scope affords protection.

In addition, the impetus to grow dramatically tends to be higher for players aiming to access the industry's first tier than for industry giants that already achieved that status. Ambitious growth strategies often entail significant financial and implementation risks.

Accordingly, we pay much attention to management's plans for achieving earnings growth. Can existing businesses provide satisfactory growth, especially in a low-inflation environment, and to what extent are acquisitions or divestitures necessary to achieve corporate goals? At first glance, a mature, cash-generating company offers a great deal of bondholder protection; but we presume a company's central focus is to increase shareholder value over the long run. In this context, a lack of indicated earnings growth potential is considered a weakness.

How Company Management Influences Business And Financial Risk

Management evaluation is an input for both business risk and financial risk profiles—reflecting the fact that management's strategy, decisions, and policies affect all aspects of a company's activity. The evaluation includes a review of the credibility and realism of management's strategy and projections, its operating and financial track record, and its appetite for assuming business and financial risk

Our judgments regarding management's strategy and operating track record help determine our view of competitive position, a key element of the business risk profile. We try to assess management's competence—and its role in determining strategic and operational success.

We bear in mind that success can be more difficult to achieve in some industries than others, simply because of the inherent risk characteristics of the business. Various airline executives, reflecting on the periodic and damaging price wars endemic to the U.S. airline industry, have observed that "you are only as smart as your dumbest competitor." Management's reputation within an industry complements our evaluations.

Each industry has its own specific challenges and constituencies that management must deal with. Heavily unionized industries, such as automakers, steel, and airlines, may face difficult labor relations—and how management handles unions and employees can determine a company's fate in cases where a strike could be fatal to operations. Relations with regulators or government officials are important in other sectors, such as utilities. Corporate governance and financial policy—including its risk tolerance—are part of our financial risk evaluation.

Strategies and plans

We compare management's future plans and assumptions with those of peer companies and with our own estimates. Implausible or overly optimistic projections can indicate poor internal planning capabilities or an insufficient grasp of the challenges (or opportunities) facing that company—especially if management fails to consider factors that peer competitors are focusing on. Indeed, one benefit of our access to management as part of the rating process is the opportunity to compare perspectives of various participants in an industry.

How strategy, plans, and policies are implemented helps determine our view of management consistency and credibility. In that exercise, determining why actual results fail to meet expectations is important. For example, meeting or exceeding projections could be the result of unanticipated good fortune, rather than a reflection of management's capabilities.

Accordingly, when reviewing projections or scenarios that are presented by management, we also strive to understand what could cause performance to deviate. We understand that forecasting is more difficult in some industries than others, and that unforeseen factors outside of management's control can upset the best-laid plans. A candid acknowledgement of risks and understanding of how various factors could affect earnings and cash flow is helpful for our internal deliberations—and may reflect favorably on management's credibility. Conversely, a record of abrupt or frequent changes in business strategy, including unexpected acquisitions, divestitures, or restructurings, definitely would raise our concern.

Acquisition strategy

Acquisitions often play a significant role in management's strategy. Although almost all mergers involve risk, well-executed acquisitions can make strategic sense. We try to fathom the company's acquisition criteria with respect to:

- Strategic "fit";
- Diversification objectives;
- Market share gains;
- Availability of excess cash resources; and
- Valuation considerations (cash flow multiples, internal rate of return, earnings accretion).

(Some of these considerations also reflect on management's overall risk tolerance and financial policy, which are discussed below in the context of financial risk.)

Management's approach and plans for poorly performing business units or those that no longer make strategic sense are a related area for investigation. Objective appraisals of businesses units and disciplined approaches to dealing with underperformers (divestiture, restructuring, or discontinuing businesses are among the options in such cases) are viewed positively.

Corporate governance and its relationship to credit analysis

Our evaluation of governance as part of credit analysis is not focused on misappropriation of funds, lack of accountability, or other misdeeds. Rather, it covers a broad array of topics relating to how a company is managed; its relationship with shareholders, creditors, and others; and how its internal procedures, policies, and practices can create or mitigate risk.

The starting point is to identify the owners of the company. The nature of the owner—e.g., government, family, holding company, or strategically linked business—can hold significant implications for both business and financial aspects of the rated entity. Ownership by stronger or weaker parent companies can substantially affect the credit quality of the rated entity. Cross-shareholding of industrial groups and family-controlled networks, commonplace in certain parts of the world, can have positive or negative implications, depending on the specific situation. We never rate corporate entities on a standalone basis.

The corporate governance of family-owned businesses, for example, introduces added complexities. Do the various family shareholders agree on strategy? Have the owners hired professional management and allowed them sufficient authority and autonomy to carry out their mission? What about management succession, or other involvement by children of the founder or owner? What about the possible desire to liquefy value in shareholdings through dividends or an IPO, and what are the implications of estate planning? Still, family ownership can hold certain advantages, in terms of adherence to long-term strategic goals and commitment of family resources to a business.

Ownership by private equity firms has become more common recently in the U.S. and Europe. Such owners typically are much more actively involved in management than public shareholders, and we seek to understand private equity owners' strategy for the company being rated. Is the company a platform for organic growth, industry consolidation, or a cash cow? What is the typical holding period and exit strategy for the owners? Repaying debt (often incurred in a leveraged acquisition of the company) and eventually selling to a strategic buyer or through an IPO is likely to be a more creditor-friendly strategy than debt-financed dividends. Some of the larger private equity companies own multiple rated companies, giving us a track record by which to judge the owners' statements of intent when a new investment of theirs is being rated.

The existence of more than one owner introduces the potential for conflicts over control. Joint owners might disagree on how to operate the business. Even minority owners can sometimes exercise effective control or at least frustrate the will of the majority owners. Whenever control is disproportionate to the underlying economic interest, the incentives for the stakeholders could diverge. This could result from existence of classes of shares with super voting rights or from owning 51% in each of multiple layers of holding companies. In either example, control might rest with a party that holds only a relatively small economic stake.

(Conventional, equity-oriented corporate governance analysis is very sensitive to share structure—for example, whether each type of share provides representational voting—out of concern that management or majority owners will act to the detriment of minority shareholders. Although this concern is not the direct focus of our credit analysis, there is a penalty for companies considered abusive to minority holders. Perception of such conduct would, obviously, impair the company's access to investment capital. Furthermore, if a company mistreated one group of stakeholders, there would be serious concern that it could later try to shortchange other stakeholders, including creditors.)

Our evaluation of corporate governance is sensitive to potential organizational problems. These include situations where:

- There is significant organizational reliance on an individual, especially one who may be nearing retirement;
- The transition from entrepreneurial or family-bound to professional management has yet to be accomplished;
- Management compensation is excessive or poorly aligned with the interests of stakeholders;
- There is excessive management turnover;
- The company is involved in legal, regulatory, or tax disputes to a significantly greater extent than its peers;
- The company has an excessively complex legal structure, perhaps employing intricate off-balance-sheet structures;
- The relationship between organizational structure and management strategy is unclear;
- The finance function and finance considerations do not receive high organizational recognition; and
- The company is particularly aggressive in the application of accounting standards, or demonstrates a lack of opaqueness in its financial reporting.

And recent examples of poor corporate governance have contributed to impaired creditworthiness. These cases included:

- Uncontrolled dominant ownership influence that applied company resources to personal or unrelated use;
- Uncontrolled executive compensation programs;
- Management incentives that compromised long-term stability for short-term gain; and
- Inadequate oversight of the integrity of financial disclosure, which resulted in heightened funding and liquidity risk.

Still, board structure and involvement has not figured prominently in the rating process. Of course, if it is evident a company's board of directors is passive and does not exercise the normal oversight, it weakens the checks and balances of the organization. But considerations such as the proportion of independent members on the board of directors, presence of independent directors in the board-level audit committee, and the compensation of directors and senior management teams have limited relevance. It can be difficult to determine objectively whether a given level of compensation is excessive, or will result in a company strategy that is overly aggressive or mainly focused on short-term performance.

Indeed, strong corporate governance—in the conventional sense, demonstrated in part by the presence of an active, independent board that participates in determining and monitoring the control environment—does not by itself provide enhancement to creditworthiness. Governance qualities cannot overcome a weak business or financial risk profile, although they might contribute to protecting an already strong business.

Financial policy and risk tolerance: managing the balance sheet and more

We assess financial policies for aggressiveness/conservatism, sophistication, and consistency with business objectives. We attach great importance to management philosophies and policies involving financial risk. Accounting practices, capital spending levels, debt tolerance, merger activity, and asset sale frequency are all aspects of a management's financial policies *(see "Credit FAQ: Knowing The Investors In A Company's Debt And Equity," published April 4, 2006, on RatingsDirect).*

Policy differences between companies can be driven by various factors, including management preferences, business requirements, and/or shareholder value considerations. Policies should optimize for the typically divergent interests of the company's stakeholders—shareholders, creditors, customers, and employees, among others. Specifically, the company's goals with respect to its credit rating also need to be consistent with the balancing of those interests.

Sophisticated business managers have thoughtful policies that target a variety of financial measures and acknowledge the interplay between business and financial risk. But a surprising number of companies have not given their financial policy serious thought, much less reached strong conclusions. For many others, debt leverage (either debt to capital or debt to EBITDA, calculated without any adjustment to reported figures) is the only focal point of such policy considerations.

In all cases, what corporate management says it will do must be viewed in the context of what it actually does and what makes sense for that entity to do. For example, an organization's leverage goals should be judged relative to its past record and future business requirements. A company that is increasing its capital spending beyond what can be met from internal cash flow should not be forecasting declining leverage unless there is a corresponding plan to sell assets or common equity. A skeptical analyst would question management on how exactly it plans to achieve both goals. The answers, and the company's subsequent performance, reflect on management's risk tolerance and credibility.

The analyst must consider the realistic choices available to management and how it responds. Similarly, debt usage and shareholder rewards need to be judged within the context of the company's cash-generating capabilities and the stability of those cash flows. We view a debt-financed dividend as very risky for a weak company with volatile cash flows, but such a move could be reasonable for a company that is generating substantial free cash flow and has already achieved a solid balance sheet.

We do not encourage companies to manage themselves with an eye toward a specific rating. The more appropriate approach is to operate for the good of the business as management sees it, and let the rating follow. Certainly, prudence and credit quality should be among the most important considerations, but financial policy should be consistent with the needs of the business, rather than an arbitrary constraint. If management forgoes attractive business opportunities merely to avoid financial risk, the company may be making a poor strategic decision, sacrificing long-term credit quality for near-term balance sheet considerations.

In any event, pursuit of the highest rating attainable is not necessarily in the company's best interests. While 'AAA' is our highest rating, we do not suggest that it is the "best" rating. Typically, a company with virtually no financial risk is not optimal as far as meeting the needs of its various constituencies. An underleveraged company is not minimizing its cost of capital, thereby depriving its owners of potentially greater value for their investment. In this light, a corporate objective of having its debt rated 'AAA' or 'AA' is ordinarily suspect. Whatever a company's financial track record, an analyst must be skeptical if corporate goals are implicitly irrational. A company's "conservative financial philosophy" must be consistent with its overall goals and needs.

A high credit rating usually is more important for financial institutions than industrial companies. For companies with solid business risk profiles and the financial capacity to target ratings within investment grade, various motivations can affect financial policy. Two examples are the balancing of financial risk against cost of capital and reliable access to commercial paper markets. The former often leads to a target rating in the range of 'BBB+' to 'A'. The latter may suggest seeking a 'BBB' or 'BBB+' rating, which typically coincides with an 'A-2' commercial paper rating. Customer perception can be another motivating factor. Some defense companies say maintaining an investment-grade rating is important when selling weapons to governments outside the U.S.

Tolerance for risk extends beyond leverage. The mixture of fixed-rate and floating-rate debt (including use of derivatives to manage that) offers an example. Generally speaking, long-term assets such as factories are best financed using fixed-rate debt, while short-term working capital financing may be accomplished using floating-rate borrowings. Management should develop an appropriate maturity schedule and liquidity targets.

For companies with defined-benefit pension plans, management makes choices regarding the mix of investment assets. The proportions of equity, fixed-income, and other investment assets should be developed with a view to the relative volatility of those investment assets. We review such investment choices and compare assumptions (e.g., discount rate) with those of other companies in the same industry. Other potential sources of earnings and cash flow volatility are exposure to foreign exchange or commodity price movements. Use of derivatives to manage such exposure is reviewed as part of our overall financial risk assessment, but the choices made by management also reflect on its appetite for risk.

Accounting And Financial Reporting

A company's financial reports are the starting point for the financial analysis of a rated entity (or issue). Such analysis must consider the accounting basis a company uses to prepare its financial reports and the implications of the varying methodologies and assumptions on the reported amounts.

Understanding the implications of the accounting basis used—e.g., International Financial Reporting Standards (IFRS), U.S. Generally Accepted Accounting Principles (U.S. GAAP), or other local or statutory GAAP basis—is highly germane to our corporate rating methodology. But analytical challenges exist even for companies using the same accounting basis, because accounting rules often provide optional treatment for certain items (e.g., LIFO rather than FIFO to account for inventory under U.S. GAAP, optional hedge accounting, or optional revaluation of certain assets or liabilities under IFRS). Moreover, as business transactions have become increasingly complex, related accounting rules and concepts have correspondingly grown more complex—and in many cases, subject to greater reliance on estimates and judgments.

Accounting failures in the early 2000s highlighted several fundamental shortcomings of the financial reporting process and its ability to comprehensively address the information needs of financial statement users. Shortcomings include both recognition and measurement issues (e.g., under what circumstances an item such as a special-purpose entity, or a "synthetic lease" should be reflected on or off a company's balance sheet, and at what value), and transparency issues (e.g., what a company should disclose about the nature of off-balance sheet commitments, compensation arrangements, or related-party transactions).

These failures also reinvigorated the debate on the merits of using a principles-based, rather than a rules-based, accounting standards framework, and served as a catalyst for expediting convergence of global accounting standards. Relatively rapid rates of accounting rules changes have occurred—often hampering meaningful period-over-period comparisons. In addition, the broader concerns about clarity and accuracy of financial reports have been evidenced by a considerable increase in restatements.

To address these challenges, we have increased and systematized the emphasis we place on the understanding of issuers' accounting characteristics. We supplement our analysis with enhanced financial statement analysis both in terms of qualitative and quantitative considerations. Our ratings criteria include numerous quantitative adjustments we often make to reported financial results to increase consistency among peers, and to better align with our view of the underlying economic reality of a particular circumstance or transaction. Our analysts also employ adjustments to portray what we view as a more appropriate depiction of recurring activity. For example, we may adjust financial measures to exclude gains or losses that we view as unsustainable or nonrecurring.

As part of our ongoing surveillance process, we consider the impact of changes in accounting standards and the impact of special events or items reported by an issuer (e.g., acquisitions, dispositions, write-offs, internal control matters, restatements, and regulatory actions). As the amount of disclosure in financial statements varies by company and by jurisdiction, we engage in differing levels of interaction with our issuers to obtain additional data beyond what is reported in the company's financials.

Evaluating accounting characteristics in the rating process

Our analysis of an issuer's financial statements begins with a review of the accounting characteristics, to determine whether the ratios and statistics derived from the statements can be used appropriately to measure the rated issuer's performance and position relative to both its peer group and the larger universe of corporate issuers. (The rating process is, in part, one of comparisons, so it is important to have a common frame of reference.) In doing so, we take an analytic rather than forensic approach.

The recent adoption of, or moves to adopt, IFRS in many countries—including Australia, Canada, and across the EU—as well as the ongoing effort to converge U.S. GAAP and IFRS, continues to further enhance comparability among companies. However, this ought not be seen as a panacea. Within IFRS, U.S. GAAP, and the separate national accounting systems, companies may choose among alternative accounting methods—for example, historical or amortized cost, as opposed to fair-value methods—and the resulting differences can have a significant effect on comparability among peers. In addition, even in applying the same methods within the same accounting frameworks, companies show varying degrees of aggressiveness in the underlying estimates and judgments they employ. Moreover, the carrying value of assets and liabilities can be greatly influenced by the historical development of a company—for example, whether it has grown primarily through internal development or through acquisitions, or whether it previously underwent a leveraged buyout or bankruptcy reorganization.

A company's scope of consolidation is an example of a key accounting characteristic that we consider to determine the relevant economic entity for analytical purposes. We look at whether there are non-consolidated affiliates, including joint ventures, where the company does not exert a high degree of control but which we feel should be consolidated for analytical purposes (given our assessment of their strategic importance, including ownership positions, the size of the investments and whether a unique, interdependent customer/supplier relationship exists) even though they may be properly excluded from consolidation for accounting purposes. Consider The Coca-Cola Co. and PepsiCo Inc., where certain key unconsolidated bottling companies are viewed as part of an entire economic system: We accordingly consolidate these entities for analytical purposes. The converse may be true when we deconsolidate an entity that is properly consolidated for accounting purposes. There are many examples of industrial companies or diversified holding companies that consolidate financial or insurance subsidiaries; for analytical purposes, we use the equity method for such nonhomogenous business activities, to avoid the distortions that would pertain as reported.

With respect to a company's hedging and risk management policies and related accounting for derivative instruments, accounting results vary widely among companies, and commonly fail to adequately depict the underlying economics. Our framework for analyzing derivative use focuses on the business, financial, liquidity, controls/risk management, and financial statement risks. This analysis includes a determination of whether a company is using derivatives for trading and/or risk management purposes, and whether a company avails itself of special hedge-accounting treatment. As this area is both complex and fraught with inadequate disclosure by many issuers, our review often entails interaction with management to properly assess a company's derivative use and risk management practices.

The accounting characteristics we review and the emphasis placed on each depend on the nature of, and activity in, the industry in which the entity operates. For example, analyzing inventory and related consideration may be important for a manufacturing company, but less relevant for a hotel management company: Likewise, the analysis of oil or natural resources reserves or the use of percentage of completion accounting is relevant to only a handful of industries.

Analytical adjustments to financial statements

Making analytical adjustments to amounts reported in the financial statements of the companies we rate traditionally has been an integral part of our rating process. We make analytical adjustments to better portray economic reality and to level the reporting differences among companies, e.g., to arrive at measures we believe enable more meaningful peer and period-over-period comparisons; better reflect underlying economics; better reflect creditors' risks, rights, and benefits; and facilitate more robust financial forecasts. It is rarely possible to completely recast a company's financial statements, but making these analytical adjustments improves the analytical relevance and consistency of the financial ratios that we use in our credit analysis.

(Although our adjustments revise certain amounts reported by issuers under applicable accepted accounting principles, that does not imply that we challenge the application of said principles by the issuer, the adequacy of its audit or financial reporting process, or the appropriateness of the accounting basis used to fairly depict the issuer's financial position and results for other purposes. Rather, our methodology reflects a fundamental difference between accounting and analysis. The accountant necessarily must find one number to use in presenting financial data. The analyst, by definition, picks apart the numbers. Good analysis looks at multiple perspectives, then uses adjustments as an analytical tool to depict a situation differently for a specific purpose or to gain another vantage point.)

Examples of common adjustments include:

- Trade receivables sold or securitized;
- Hybrid securities;
- Surplus cash and "near cash" investments;
- Capitalized interest;
- Share-based compensation expenses;
- Captive finance activity; and
- Asset retirement obligations.

(See "Ratios And Adjustments" chapter for a full list and discussion.)

Changes in accounting standards

As part of our surveillance process, we monitor the potential impact of recent and pending changes in accounting and disclosure standards, and other legislation affecting information included in financial reports. Accounting changes should not have any direct impact on credit quality unless they reveal new information about a company, which then needs to be factored into our understanding of the company. (For example, the ratings for a few U.S. companies were lowered following the implementation of new accounting for retiree medical liabilities in the early 1990s, because little information was previously available about these obligations.) However, accounting changes can produce indirect effects. These include triggering of financial covenant violations; regulatory or tax consequences; or adverse market reactions as a result of changes in market sentiment about the company's apparent leverage, profitability, or capitalization; and, accordingly, can even influence changes in business behavior.

Consider the example of U.S. accounting standard SFAS No. 158, which requires full recognition of pensions and other postretirement obligations (e.g., retiree healthcare) on the sponsoring employers' balance sheet. Because we have long reflected an issuer's full postretirement liability by virtue of our adjustments to leverage and capitalization ratios, the adoption of this pronouncement has no direct ratings implications. However, the potential ancillary effects could be equally important to our consideration: As a result of the new standard, many companies will report substantially lower shareholders' equity and will appear more leveraged—and could affect dividend policies. In addition, many employers are changing the structure and funding levels of their postretirement plans as a consequence of changes in legislation and accounting standards, resulting in potential changes to amounts and timing of related cash flows.

Another example of changes in accounting standards that caused pronounced behavioral shifts: SFAS No. 123R, requiring the expensing of stock-options and other share-based payments. In anticipation of that change, many companies chose to accelerate the vesting of employee stock options in the year prior to adoption. The effect of such acceleration was to move compensation expense that would have been recognized in 2006 and future years to a pre-adoption year. (Such recognition was not required; only pro forma footnote disclosure of the expense was required under pre-SFAS No. 123R rules.) In addition, many companies have reconsidered their use of share-based pay as a result of the expensing requirement, and have made changes to their employee compensation plans—resulting, for some, in real changes to cash flows.

Information risk, restatements, and disclosure of significant events

To the extent we believe information risk exists, it can influence our decision to maintain a rating, assign a rating in the first place, or the level of the rating assigned. In cases where the information risk is so significant that it precludes meaningful analysis we would decline to assign a rating, or, where a rating is already assigned, withdraw or suspend that rating.

However, we ordinarily rely on the issuer's audited financial statements and the inherent checks and balances in the financial reporting process. Our analytical process does not include an audit, nor does it include a process of "verification."

A rating can sometimes be assigned even in the absence of audited financial statements. This especially is the case when a new company is formed from a division of another company that did produce audited financial statements. In other cases, there may be unaudited data—such as oil-production data—that corroborates company results.

Further, much additional information that is provided to us by management is unaudited, including preliminary financial data, quarterly financial statements, projections, operating data, pro-forma financial statements, cash flow data, and various scenario analyses, to name a few. We incorporate such data at our discretion, making judgments about the reliability of each input.

There have been many situations—especially recently—where rated companies have delayed filing their financial reports for various reasons, sometimes for significant periods of time. Such reporting delays, too, require judgment regarding the implications, if any, for credit quality. We have no monolithic approach to such situations, rather, additional interaction with the company is required, as part of our surveillance process during the period in which formally issued and audited financial statements are lacking. Our interaction includes determining the cause for the delay and potential consequences, obtaining interim financial reports, discussing how the company is addressing ensuing regulatory or covenant matters, discussing liquidity prospects, and internal control matters, among others.

Filing delays happen for many reasons: In some cases, because of a restatement of prior-year financials; in others, from a review of an alleged financial-statement irregularity, or issues discovered with a company's internal controls process.

In any event, we are cognizant that lengthy reporting delays can result in adverse regulatory reactions and covenant compliance uncertainty. Delays, restatements, material weaknesses, and related investigations also can lead to other adverse results, such as auditor changes, personnel changes, lawsuits, management distraction, increased compliance costs, and challenges in accessing the capital market—the impact of which must be closely evaluated in our ratings process. The impact these events have on a rating depends on the unique facts and circumstances of each case.

With respect to violation of covenants, a liquidity crisis could result. Technical and actual defaults (including cross defaults) require waivers under debt agreements, and sometimes result in a company receiving a notice of default. Sometimes the question of whether or not a filing delay results in a default is not immediately clear when the delay is announced, or during the period of delay. In some cases, detailed information may not be available for some time, and we will react as we deem appropriate, based on our analysis of the best available information, through CreditWatch actions and intermediate rating changes, or—in extreme cases—withdrawal of the ratings.

In general, the impact of the instances involving financial-statement irregularities is hard to predict. The underlying reality can range from an almost trivial problem to a complete audit and financial failure. Occasionally, a small problem can turn into a large one, as headline risk takes a toll on the company's access to financing. We critically weigh how pervasive these issues are, how they affect the enterprise's reputation and its ability to conduct future business, and broadly how proactively management and the board approach resolution to these matters.

Cash Flow Adequacy

Cash flow analysis focuses on understanding and forecasting how cash is generated and spent by a business. It incorporates identifying a company's cash flows, determining trends and sustainability, distinguishing operating from investing and financing flows, and understanding potential sources of distortion and future volatility.

All this must be considered in the context of a company's individual characteristics, such as, where it is in its life cycle. The ability to generate cash is determined by a firm's business prospects—competitiveness, market dynamics, economic environment, etc., while its need for cash is a consequence of the balance-sheet structure, management's financial strategy, and strategic needs.

An enterprise's capacity to pay debts or any other obligation, the core underlying concept of a credit rating, is determined by the ability to generate cash—not earnings, which is an accounting concept. Although there is generally a strong correlation between operating cash flow and profitability in the long run, many transactions and accounting entries may affect one and not the other during a specific period. Aggressive accounting policies, for example, regarding revenue and expense recognition, asset write-downs, or adjustments to depreciation schedules, can have a material impact on earnings and none whatsoever on actual cash generation.

Liquidity pressures can arise even when a company reports robust earnings—e.g., when gains not realizable in cash for a lengthy period comprise a significant component of earnings or where the enterprise faces large capital expenditure requirements. Accordingly, cash flow adequacy is typically the single most critical aspect of credit rating analysis.

Measuring cash flow

Discussions of cash flow often suffer from lack of a uniform definition of terms. Our analysts use numerous cash flow measures in the credit decision process, and the terms we use to define specific cash flow concepts are summarized here.

We begin to measure an issuer's operating cash flow generation using its funds from operations (FFO), which is defined as net income from continuing operations adjusted for depreciation, amortization, and other noncash and nonrecurring items such as deferred taxes, write-offs, gains and losses on asset sales, foreign exchange gains and losses on financial instruments, and undistributed equity earnings or losses from joint ventures.

The availability of cash for debt service for companies on a high growth spurt is ordinarily better appreciated after backing out the changes in working capital, and arriving at the operating cash flow (OCF). The use of the FFO metric for some regulated utilities, for instance, can be misleading as it does not capture the variation in regulatory assets or liabilities. In Brazil, for example, tariffs are revised only annually: the time gap between when the actual cash revenues or costs occur and the recognition in the income statement is substantial and might affect different fiscal years. Similarly for working capital-intensive industries such as retailing, OCF may be a better indicator of the firm's actual cash generation. Working capital, on the other hand, could be managed or manipulated by management depending on its liquidity or accounting needs. Accordingly, FFO has been frequently used as a comparative indicator of cash from operations. As OCF tends to be more volatile, FFO is often used to smooth period-over-period variation in working capital. It is used as a better proxy of recurring cash flow generation rather than the actual cash flow generated by the ability to manage working capital.

By deducting capital expenditures from OCF we arrive at free operating cash flow (FOCF), which can be used as a proxy of a company's cash generated from core operations. We sometimes exclude discretionary capital expenditures for capacity growth from the FOCF calculation, but in practice, it is often difficult to discriminate between expansion and replacement. And, while companies do have some flexibility to manage their capital budget to weather down cycles, such flexibility is generally temporary and unsustainable in light of intrinsic requirements of the business. For example, companies can be compelled to increase their investment programs because of strong demand growth or technological changes. Regulated entities (e.g., telecommunication companies) might also face significant investment requirements related to their concession contracts.

We calculate a company's discretionary cash flow by subtracting cash dividends (including to minority interests) from FOCF. The discretion in dividend pay-out will depend on a company's financial strategy. Companies with aggressive dividend pay-out targets might be reluctant to reduce the level of dividends even under some liquidity pressure. In addition, dividends of investment-grade companies are less likely to be reduced following some reversals—although they ultimately are discretionary.

Finally, cash used for acquisitions and/or received from asset disposals and other miscellaneous sources and uses of cash are subtracted or added to discretionary cash flow, and prefinancing cash flow is the end result. This metric represents the extent to which a company's cash flow from all nonfinancing sources has been sufficient to cover all internal needs, including the payment of dividends. We then reconcile prefinancing cash flow to various categories of external financing activity, such as borrowing or repayment, equity issuance, and to changes in the company's cash balances.

While EBITDA is a widely used indicator of cash flow, it has significant limitations. Because EBITDA derives only from income statement inputs, it can be distorted by the same accounting issues that limit the use of earnings as a basis of cash flow. Besides, EBITDA overlooks balance sheet items that might be tying or freeing up cash. It is better suited for more established companies, especially in relation to industry benchmarks.

Potential distortions affecting cash flows

Distortions to cash flow may arise from timeliness of income or expense recognition, classification of items, and other accounting issues. For example, the period in which companies choose to recognize income and expenses (such as the charge-off of uncollectible items, asset disposals, repairs and maintenance, etc.) depends on applicable GAAP, which may be subject to estimates and management's discretion.

Because cash flow is an indicator of a company's health and prospects, there is a bias to enhance apparent cash generation by treating cash inflows as operating in nature, and cash outflows as investing or financing in nature. But loose classification of flows into operating, investing, or financing can distort their true nature. Classification of investments as trading, available-for-sale, or held-to-maturity dictates if related cash-flows are treated as operating or investing. Operating margin hedging program results are treated as financing—while they reflect operational strategies.

Another source of distortion is translation of foreign-currency. Swings in working capital may only reflect the volatility of the foreign currency, and not the actual cash in the original currency. We would prefer to analyze working capital in the original currency—and reflect translation effects in a separate cash-flow entry.

Cash flow ratios

Analysts are encouraged to look at more than a single measure, to develop several perspectives. A company's individual characteristics and its business cycle will be better captured in certain ratios than in others.

Where long-term viability of a company is more certain (i.e., for more highly rated credits), there can be greater analytical reliance on FFO and its relation to total debt burden. In addition, more established, healthier companies usually have a wider array of financing possibilities to cover potential short-term liquidity needs and to refinance upcoming maturities. For more marginal situations, the focus shifts to free cash flow—after the various uses have been subtracted—and this is more directly related to current debt service. Some of the cash-flow metrics most used by our analysts include:

Debt payback ratios

- Funds from operations (FFO)/total debt: the most frequently used credit measure in industrial ratings;
- Operating cash flow (OCF)/total debt: captures working capital requirements;
- Debt/EBITDA: used as a proxy of debt repayment capacity for high-yield issuers; it can overstate repayment capacity by excluding interest burden—usually high for speculative ratings;
- Total debt/discretionary cash flow: provides an indication of how many years would be required to repay outstanding debt using current cash flows, but is subject to changes in dividend policy;
- Free operating cash flow (FOCF)/total debt: indicates a company's capacity to pay debt with internal operating cash flow; it is more critical when analyzing weaker companies, because speculative-grade issuers typically face near-term vulnerabilities that are better measured by free cash flow ratios.

Debt service ratios

- EBITDA/interest expenses: useful because of its simplicity, wide usage, and industry reference (peer comparisons, financial covenants, etc.);
- FOCF + interest expenses/interest expenses: similar to the EBITDA/interest ratio, but more comprehensive (after taxes, working capital and capital expenditure) and with lower potential for distortions;
- FOCF + interest expenses/interest expenses + 12-month debt maturities: measures the ability to pay interest and principal out of free cash flow; more appropriate for projects and entities with amortizing debts.

Financial flexibility ratios

- FFO/capital expenditures: indicates a company's internal flexibility to meet its capital budget;
- Capital expenditure/depreciation expense: a low ratio (typically, less than 100%) could indicate problems in the rate of replacement of plant and equipment—a strong ratio may indicate high-growth industries, and is needed to keep up with the competition.

Interpretation of ratios is not straightforward, and careful analysis always is required, because a similar ratio might lead to different conclusions, depending on company specifics. A company serving a low-growth or declining market may exhibit relatively strong free cash flow because of diminishing fixed and working capital needs. Growth companies, in contrast, exhibit thin or even negative free cash flow because of the investment needed to support growth. For the low-growth company, credit analysis weighs the positive, strong current cash flow against the danger that this high level of protection might not be sustainable. For the high-growth company, the opposite is true: Weighing the negatives of a current cash deficit against prospects of enhanced protection once current investments begin yielding cash benefits.

There is no simple correlation between creditworthiness and current levels of cash flow. Even for peer companies with very similar cash flow coverage ratios, the rating outcome can be very different, depending on their other business and financial characteristics.

Balance Sheet And Asset Protection

The main ratio we use for leverage analysis is total debt/total debt + equity.

What is considered "debt" and "equity" for the purpose of ratio calculation is not always so simple, and requires extensive analytical input. Our computation of total debt includes various off-balance sheet liabilities and analytical adjustments, as noted in the section on cash flow analysis. Similarly, the amount of equity is adjusted for hybrid securities in all their variations. *(See Hybrid instruments section of "Ratios And Adjustments" chapter for our adjustments and how we calculate them.)*

We sometimes calculate supplemental ratios that incorporate the market value equity. These can have especial relevance in comparing companies with significant intangible assets. Traditional measures focusing on long-term debt have lost much of their significance, because companies rely increasingly on short-term borrowings. It is now commonplace to find permanent layers of short-term debt, which finance not only seasonal working capital but also an ongoing portion of the asset base.

Generally, we do not net out cash from the debt amount; however, we adopt a "net debt" approach in some situations, especially in countries (such as Japan and in Europe) where local practice is to maintain a large portfolio of cash and marketable securities. (In these situations, we also focus on cash flow to net debt.) Each situation is analyzed on a case-by-case basis, subject to additional information regarding a company's liquidity position, normal working cash needs, nature of short-term borrowings, and funding philosophy. Funds earmarked for future use, such as an acquisition or a capital project, are not netted out. This approach also is used in the case of cash-rich U.S. pharmaceutical companies that enjoy tax arbitrage opportunities with respect to these cash holdings.

In the case of hybrid securities, too, the analysis is based on their specific features—not the accounting or the nomenclature. For debt that is convertible at the discretion of the investor, depending on the future value of the common shares, it would be somewhat presumptuous for us to predict whether and when conversion will occur, so we ordinarily give little, if any, weight to the conversion potential.

Original-issue discount debt, such as zero coupon debt, is included at the accreted value. However, since there is no sinking fund provision, the debt increases with time, creating a moving target. (The need, eventually, to refinance this growing amount represents another risk.)

Nonrecourse debt is often included in the calculation; moreover, even nonrecourse debt of a joint venture may be attributed to the parent companies, especially if they have a strategic tie to the operation. The analysis may burden one parent with a disproportionate amount of the debt if that parent has the greater strategic interest or operating control or its ability to service the joint-venture debt is greater. Other considerations that affect a company's willingness to walk away from such debt—and other nonrecourse debt—include shared banking relationships and common country location. In some instances, the debt may be so large in relation to the owner's investment that the incentives to support the debt are minimized. In virtually all cases, however, the company likely would invest additional amounts before deciding to abandon the venture. Accordingly, adjustments would be made to reflect the owner's current and projected investment, even if the debt were not added to the (parent) company's balance sheet.

More fundamentally, the nature and valuation of a company's asset mix is critical to determining the appropriate leverage for a given level of risk. Assets with stable cash flow or market values justify greater use of debt financing than those with clouded marketability. For example, grain or tobacco inventory are viewed positively, compared with apparel or electronics inventory; transportation equipment is viewed more favorably than other equipment, given its suitability for use by other companies.

Accordingly, we believe it is critical to analyze each type of business and asset class in its own right. While FASB and IAS now require consolidation of nonhomogenous business units, we analyze each separately. This is the basis for our methodology for analyzing captive finance companies.

Asset valuation

Knowing appropriate values to assign a company's assets is key to our analysis. Leverage as reported in the financial statements is meaningless if the assets' book values are materially undervalued or overvalued relative to economic value.

We consider the profitability of an asset as an appropriate basis for determining its economic value. Market values of a company's assets or independent asset appraisals can offer additional insights. However, there are shortcomings in these methods of valuation—just as there are with historical cost accounting—that prevent reliance on any single measure. (Similarly, using the market value of a company's equity in calculations of leverage has its drawbacks. The stock market emphasizes growth prospects and has a short time horizon; it is influenced by changes in alternative investment opportunities and can be very volatile. A company's ability to service its debt is not affected directly by such factors.)

The analytical challenge of which values to use is especially evident in the case of merged and acquired companies. Accounting standards allow the acquired company's assets and equity to be written up to reflect the acquisition price, but the revalued assets have the same earning power as before; they cannot support more debt just because a different number is used to record their value. Right after the transaction, the analysis can take these factors into account, but down the road the picture becomes muddied. We attempt to normalize for purchase accounting, but the ability to relate to pre-acquisition financial statements and to make comparisons with peer companies is limited.

Presence of a material goodwill account indicates the impact of acquisitions and purchase accounting on a company's equity base. Intangible assets are no less "valuable" than tangible ones, but comparisons are still distorted, because other companies cannot record their own valuable business intangibles, i.e., those that have been developed, rather than acquired. This alone requires some analytical adjustment when measuring leverage. In addition, analysts are entitled to be more skeptical about earning prospects of an acquisitive company when these rely on turnaround strategies or "synergistic" mergers.

Preferred stock

Preferred stocks can qualify for treatment as equity or be viewed as debt—or something between debt and equity—depending on their features and the circumstances. Preferred stocks with a maturity receive diminishing equity credit as they progress toward maturity.

Preferred stock that may eventually be refinanced with debt is viewed as a debt equivalent, not equity, all along. While "perpetual" on the surface, these securities often are merely a temporary debt alternative for companies that are not current taxpayers, until they once again can benefit from tax deductibility of interest expense. Redeemable preferred stock issues may be expected to be refinanced with debt once an issuer becomes a taxpayer. Preferreds that can be exchanged for debt at the company's option also may be viewed as debt in anticipation of the exchange. However, the analysis also would take into account offsetting positives associated with the change in tax status. Often the trigger prompting an exchange or redemption would be improved profitability. Then, the added debt in the capital structure would not necessarily imply lower credit quality. The implications are different for many issuers that do not pay taxes for various other reasons, including availability of tax-loss carry-forwards or foreign tax credits. For them, a change in taxpaying status is not associated with better profitability, while the incentive to turn the preferred into debt is identical.

Auction preferreds are even more problematic, given that the holders of these preferreds would pressure for redemption in the event of a failed auction or even a rating downgrade.

Liquidity

Gradual erosion in a company's fundamentals can ultimately lead to liquidity problems. Yet, even a company with a solid business position and moderate debt use, can, when faced with sudden adversity, experience an actual or potential liquidity crisis, or an inability to access public debt markets. Possible causes of such adversity include:

- A dramatic setback in the business caused by, for example, a crisis in consumer confidence, such as the precipitous market downturn following the terrorist attacks of Sept. 11, 2001. In particular, this event had a significant negative impact on the airline and travel-related industries.
- A large, adverse litigation judgment.
- Real or alleged management impropriety, including accounting abuses such as those at Enron Corp. in 2001, and Tyco International Ltd. in 2002.
- Large derivatives or trading losses.
- Sovereign intervention, for example, in the form of foreign currency controls, controls on bank deposits, or pricing controls, such as those in Argentina in 2002.

We consider the challenges a company confronted by a shock or triggering event would face concerning its existing debt maturities, its ability to make internal adjustments to maximize near-term cash generation, and its access to external sources of liquidity and capital. Analyzing a company's ability to cope with such extraordinary challenges is a matter of assessing its liquidity or its options under stress.

Our analytical focus here is on the downside: whether the company can meet its obligations on a rainy day, rather than just under the expected circumstances. Speculative-grade issuers are more susceptible to liquidity crises, which, in their situations, can stem from upcoming interest and principal payments, financial covenants, and availability on revolving credit facilities.

In the context of a liquidity crisis, a company's business position cannot be considered a constant: The nervousness of customers and/or suppliers might impair the company's competitive standing, contributing to a downward spiral in its fortunes. Industrial companies with finance operations may be particularly vulnerable, given the funding required for such operations. Companies with trading operations are doubly vulnerable, given the risk-averse inclination of trading counterparties, coupled with heavy funding needs.

Often, the effect of such adversities is compounded by the triggering of contingent provisions included in credit lines, bond indentures, counterparty agreements, or operating agreements. Triggers can change minor adversity into a major crisis for the company (and, as such, we do not view ratings or other triggers favorably). These provisions take many different forms, with the trigger based on rating downgrades, the violation of financial benchmarks or ratio levels, "material adverse changes" (as interpreted by the creditor), share price declines, or ownership changes. They may set off default, acceleration, put, or collateralization requirements.

In any event, the starting point of liquidity analysis is the maturity schedule for debt and other long-term obligations. Near-term maturities include commercial paper; sinking fund payments and final maturity payments of long-term debt; borrowings under bank credit facilities with approaching expiration dates; and mandatory redemptions of preferred stock. Other significant financial obligations may also need to be considered, for example, lease obligations, contingent obligations such as letters of credit, required pension fund contributions, postretirement employment payments, and tax payments. Even when analyzing highly creditworthy companies, it is necessary to be aware of the overall maturity structure and potential for refinancing risk.

Cash is king

The best sources of liquidity are surplus cash and near-cash on the balance sheet. This includes cash in the bank, cash equivalents, and short-and long-term marketable securities. (Indeed, we also look to some companies to maintain high cash balances against potential liquidity crises; these include bonding requirements in the case of U.S. cigarette companies, and cyclical reversals in the case of capital intensive manufacturers, such a the automobile companies.)

Of course, not all cash is surplus. Virtually every company has some base amount of cash necessary for day-to-day operations—which may be quite large, if the company is subject to wide swings in working capital. Companies with seasonal borrowing needs may build up large cash balances for use during the seasonal peak.

Additionally, restricted cash (disclosed separately) is unavailable for everyday funding and should not be factored into a liquidity analysis, because these funds have been set aside to satisfy a specific obligation. A subsidiary's loan agreements can also restrict dividends and upstream advances. This poses a problem for a holding company that would rely on such dividends or upstream loans to access cash at the subsidiary level.

Bank overdrafts should also be deducted from available cash balances. Offshore cash may be subject to a repatriation tax, in which case it should be discounted accordingly. For companies in emerging markets, it is important to consider whether the company's liquid asset position is held in local government bonds, local banks, or local equities, and whether the issuer will have access to these assets at times of stress on the sovereign.

To fully benefit from cash and near-cash holdings from a liquidity perspective, these assets must be readily accessible and available to support the company's immediate needs. Sometimes the company may not have free access to all the cash shown on the consolidated balance sheet. For example, offshore cash may not be available for a few business days—especially if it has to be converted from a foreign currency.

Other internal sources of liquidity

Any company faced with severe liquidity pressures can be expected to make internal adjustments to maximize near-term cash flow. Considering a company's flexibility to do so is an extension of normal cash flow analysis. There are several possible options for doing this.

Cash can be extracted from working capital by monetizing receivables through factoring or securitization, liquidating unneeded inventories, or stretching out payments to suppliers. However, if, for example, no factoring or securitization facilities are already in place, these may take several months to establish. If aggressive discounting is necessary to sell inventory quickly, such liquidations could have severe implications for the company's future pricing power and brand image. In stretching payment terms to suppliers, the company runs a risk of spreading alarm about its situation and, ultimately, making suppliers unwilling to ship goods.

Companies generally have some flexibility to reduce capital expenditures from planned levels, at least temporarily. As such, we look at maintenance, rather than discretionary capital spending plans. Maintenance capital spending may include plant refurbishing, and ordinary repair work and is necessary for the company to sustain normal operations. Pollution control projects needed to meet regulatory requirements have little deferral potential. Presumably, expenditures related to growth initiatives could be put on hold, and are discretionary in nature. In any case, it may take some time to reduce expenditures to the maintenance level if the company had already entered into contractual commitments related to its planned investments.

The business implications of reducing capital spending must also be considered. Continued deferral of spending may make the company less competitive and more prone to operational problems. Additionally, beyond a certain point, management might rationally conclude that seeking protection from creditors through a bankruptcy filing would be preferable to permanently impairing the business by neglecting capital spending.

Curtailing operations with negative cash flow and divestitures

Discrete business units or product lines that are performing poorly or in a start-up mode could be suspended. Shutdown costs must be netted against the ongoing cash savings. Again, the implications of such actions for the business must also be weighed.

A company may choose to sell entire operations or lines of business to raise cash. These could include underperformers as well as strong businesses. Additionally, we consider the company's ability to realize value in light of market conditions for such assets, including the availability of interested buyers, as well as the likely time period for effecting transactions. Assets sold in a fire sale often do not recapture their full value. Dumping large blocks of stock may depress their value.

Asset sales may have mixed implications for the remaining business mix. For example, the sale of a profitable, cash-generating operation that had been the company's best business could have a negative impact on the company's business risk profile. Alternatively, a money-losing unit with heavy capital requirements could improve the business risk profile while bringing in some much needed cash.

Dividend deferrals offer a quick source of cash savings. But, dividend cuts often are visible signals of distress, and the negative perception in the capital markets that may result must also be considered: At the very least, such actions may hinder further equity issuance. Additionally, extended deferral of preferred dividends may create a growing liability on the balance sheet.

External sources of liquidity

A company's ability to tap external sources of funding may be jeopardized when it is overly reliant on one source of financing. In general, a company's experience with different financial instruments and capital markets gives management alternatives if conditions in a particular market suddenly sour.

Company size and recognition can play a role in whether it can raise funds in the public debt markets. Similarly, a company's role in the national economy—particularly outside the U.S.—can enhance its access to bank and public funds. Large issuers in a relatively small country often are favorably positioned to attract financing from that country's banking system. External sources of liquidity, including commercial paper, bonds, bank credit facilities, and equity issuance are discussed below.

Of all the sources of debt funding, commercial paper is the least reliable. Use of commercial paper to fund short-term assets (typically, inventory and receivables) or as a small component of a company's long-term funding is fairly common. However, when faced with severe adverse circumstances, companies often will not be able to roll over outstanding commercial paper as it matures—let alone raise additional sums.

Typically, only companies viewed as having a strong credit standing can access the market. The market for commercial paper rated 'A-2' or lower is much smaller than the market for that rated 'A-1' or 'A-1+', in part because of SEC regulation 2(a)7, which severely restricts holdings of lower-rated commercial paper by U.S. money market funds. The U.S. market for commercial paper rated 'A-2' or lower in 2007 was estimated to total about $72 billion, compared with the approximately $1.7 trillion of 'A-1' and 'A-1+' paper outstanding. Moreover, the 'A-2' market is subject to significant pressure during credit crunches.

When market fears build regarding a particular issuer, the term of commercial paper the issuer can place typically shrinks to a few days, thereby heightening refinancing risk. Market confidence can be lost very quickly. This was evident following Altria Inc.'s loss of access to the commercial paper markets following an unfavorable verdict and $12 billion bonding requirement in the Price class action lawsuit. And, in addition to legitimate concerns about a declining credit, the market can be spooked by unwarranted fears. For example, Columbia Gas Systems Inc. unexpectedly filed for bankruptcy protection in 1991 because of onerous natural gas take-or-pay obligations. Suddenly, other natural gas pipeline companies, many of which had minimal take-or-pay exposure, found it difficult to sell commercial paper.

Backup liquidity

Given the commercial paper market's acute sensitivity to credit quality, and the speed with which confidence can be lost, we consider it prudent for companies that issue commercial paper to make arrangements in advance for backup sources of liquidity. Backup liquidity protects a company from defaulting if it is unable to roll over maturing paper with new notes because of shrinkage in the overall commercial paper market, or an issuer's inability to access the commercial paper market because of company-specific issues.

Backup for commercial paper generally is provided by committed credit facilities, yet sometimes may take the form of excess cash that is specifically committed for this purpose. *(For a discussion of our commercial paper backup policies, see "Commercial Paper.")*

Bonds

The public bond market is far less risk-averse than the commercial paper market. Most investment-grade companies in the U.S. can gain access to the public debt market for a new bond issue at a reasonable rate. In other, less-developed countries, the public bond market may at times become inaccessible for even the most creditworthy companies (e.g., South Korea in early 2001). Placing debt is easiest for a company that has regularly tapped the market and that can issue debt in large amounts—thereby providing investors with a more liquid secondary market.

Although the market for speculative-grade debt is very large, this market is much more volatile. Speculative-grade companies, especially those on a deteriorating trend, may well have only intermittent access to this market, depending on market sentiments and liquidity. There have been times when even

'CCC'-rated debt found ready buyers, but there have also been periods when the entire junk bond market was effectively shut down.

Whatever the general market conditions, even investment-grade companies may have difficulty issuing public debt if one of the types of shocks discussed above has occurred. In theory, a company should be able to issue debt at some price, but in practice, debt issuance may well not be feasible if there is considerable uncertainty in the market about a company's situation and underwriters are, therefore, understandably nervous about undertaking a transaction on behalf of the company.

The price of outstanding bonds may be a good gauge of market sentiments—although technical factors can also influence pricing. Obviously, if existing bond spreads have widened significantly relative to the market and are responding wildly to the day-to-day developments at a company, prospects for an additional public debt issuance are poor. (We monitor bond spreads as part of our ongoing surveillance.) The bond market has also been inaccessible during periods of overall market uncertainty following economic weakness, political changes, and terrorism actions or threats.

Bank credit facilities

Bank credit generally is a company's most reliable source for debt capital. When a company loses access to the commercial paper and public debt markets, banks are often the lenders of last resort. It is typical for banks to provide a portion of a healthy firm's company's regular financing. Speculative-grade companies have also accessed these markets more frequently in lieu of traditional public subordinated debt offerings. In some countries (including almost all less-developed markets), banks are the major source of capital for both short-and long-term needs.

Banks offer various types of credit facilities that differ widely in the commitment to advance cash under all circumstances. Weaker forms of commitment, although less costly to issuers, give banks great flexibility to redirect credit at their discretion. For example, uncommitted lines are little more than an invitation to do business at some future date, and are given little to no credit in our liquidity analysis.

The strongest facilities are those that are in place and confirmed in writing, or committed facilities. In the U.S., fully documented revolving credits represent such contractual commitments. In the absence of a contractual commitment, payment for the facility—whether by fee or balances—is important because it generally creates some moral commitment on the bank. Generally, a solid business relationship is key to determining whether a bank will stand by its client.

Dependence on just one or a few banks heightens risks. Apart from the possibility that the bank will not have adequate capacity to lend, it also may not be willing to lend to the issuer. Having several banking relationships diversifies the risk that a single bank will lose confidence in the borrower and hesitate to provide funds.

Although less common anymore, in some cases, companies establish separate credit agreements with each of their banks, which can make it unwieldy to quickly renegotiate terms of the agreements in a crisis. A group of lenders having pre-established lending commitments under a common credit agreement is generally more practical, effective, and predictable. Even here, though, some features of the agreement could greatly hinder the renegotiation process—for example, a requirement that the agreement can be modified only by unanimous consent.

Concentration of banking facilities also tends to increase the amount of an individual bank's participation. As the amount of the exposure increases, the bank may be more reluctant to meet its commitment. In addition, the potential requirement of high-level authorizations at the bank for the release of funds could create logistical problems for the issuer in quickly accessing funds. On the other hand, a company will not benefit if it spreads its banking business so thinly that it lacks a substantial relationship with any of its banks. We expect banks themselves to be financially sound, and do not favorably view marginally investment-grade banks.

As with any source of debt funding, the analyst must consider the term structure of bank credit facilities. Reliance on short-term facilities poses obvious risks. Even multiyear facilities will provide commitments for only a short time as the end of their terms approaches. We closely monitor a company's efforts to arrange for the continuation of its banking facilities well before they lapse. In normal situations, bank facility expirations may be viewed as "soft" maturities because the facilities are routinely renewed. But, if the company is under stress and the banks have lost confidence in the company's prospects, the banks might use the expiration to demand repayment.

Financial covenants and triggers

In assessing a company's access to bank capital and other sources of debt financing, the analyst must consider triggers that can block access to additional funding, accelerate the repayment of existing debt, or create a cross default with other debt obligations. The most common such triggers are financial covenants in the form of ratio benchmarks. In certain cases, investors may take comfort from knowing that covenants (e.g., leverage tests) impose discipline on an otherwise financially aggressive management by prohibiting debt-financed acquisitions and special distributions to shareholders. In severe adversity, however, tight covenants could imperil credit quality by provoking a crisis with lenders if the covenants are violated: the lenders would have the discretion to accelerate the debt, causing a default that might otherwise have been avoided. Triggers may also be in the form of credit rating changes themselves, for example, a change in rating from investment grade to non-investment grade.

In considering just how the issuer's risk profile is affected by such provisions, the key considerations are: How close the company is to the trigger thresholds; how severe and immediate the consequences are; the amounts involved; and how material the amounts are in the context of the specific company. Borrowing agreements, even of creditworthy companies, are sometimes structured with tight covenants. The initial expectation is that lenders will routinely renegotiate the terms as the issuer's circumstances change. Even here, though, the existence of covenants can be problematic if, for example, the lenders' strategies change and they wish to reduce their exposure to the borrower, or if a company is unable to meet its financial forecasts that were used as a basis of setting these covenants.

Violation of covenants in public debt issues always is serious, given the cumbersome procedure the company must follow to obtain waivers or to modify the covenants. In all cases, it is important to monitor the performance of a company against its most restrictive financial covenants. (We obtain bank loan covenant compliance reports directly from issuers, given the nonpublic information needed to compute the covenant values.)

Material adverse change (MAC) clauses represent another form of trigger. Remedies include the full range of possibilities that also apply to financial covenants. The vague definition of such clauses leaves much discretion to lenders. Still, cases of MAC clauses actually being invoked against corporate borrowers are extremely rare. The bank's reputation would suffer if it was not judicious in invoking the clause—and it would be subject to litigation. There undoubtedly have been instances, though, when companies have been dissuaded from tapping their credit facilities by the threat of a MAC clause being invoked.

Springing liens also can be problematic regarding financing flexibility. Sometimes, lenders may require the company to post collateral after a downgrade—which is provided for in the loan documentation. When assessing the impact of a springing lien, we consider how close the company is to the trigger; for example, if the company is rated 'BBB-' with a negative outlook, it is pretty close to a lien that goes into effect upon dropping to speculative grade. (With respect to recovery analysis, we always assume that a springing lien has been activated. The context for recovery analysis is a default scenario—and we assume that the trigger would have been breached in advance of default.)

Equity issuance

In theory, equity issuance is another source of capital; in practice, this source cannot be relied on in a crisis scenario. The public equity markets are extremely fickle. Selling new common stock generally is feasible only if the company is seen as having at least decent prospects and the overall stock market is favorable. Moreover, accessing the common stock market may primarily depend on management's willingness to accept dilution. We therefore do not give companies credit for potential equity issuances until such transaction has been completed.

Selling preferred stock may be more acceptable to management because this avoids dilution of the common shareholders' earnings, but this usually is viable only if the company's continuing ability to meet its preferred dividend requirements is apparent.

Companies owned by other corporate or government entities can seek fresh capital from these owners. Often a strong parent or equity sponsor is available to provide much needed capital during a liquidity crisis.

The management factor

Finally, management's skill in coping with a liquidity crisis can make the difference between corporate life and death. Prudent financial managers will:

- Avoid excessive short-term debt;
- Spread debt maturities over time;
- Maintain cordial relations and credibility with banks, during bad times and good;
- Negotiate bank loan covenants with ample cushion while the company is financially strong;
- Anticipate potential covenant defaults before they occur and renegotiate covenants on a timely basis with the bank group;
- Maintain bank lines in excess of anticipated needs, and begin negotiating renewals well before expiration; and
- Fully draw credit lines at the onset of major difficulties. ■

Ratios And Adjustments

Key Ratios And Glossary Of Terms

Table 4 Key Ratios

Ratio	Formula
Operating income before depreciation and amortization to revenues	Operating income before depreciation and amortization/revenues
EBIT interest coverage	EBIT/interest
EBITDA interest coverage	EBITDA/interest
FFO interest coverage	FFO, plus interest paid, minus operating lease adjustment to depreciation/interest*
Return on capital	EBIT/average beginning of year and end of year capital
FFO to debt	FFO/debt
FOCF to debt	FOCF/debt
Discretionary cash flow to debt	Discretionary cash flow/debt
Net cash flow to capital expenditures (capex)	Net cash flow/capex
Debt to EBITDA	Debt/EBITDA
Debt to debt plus equity	Debt/debt plus equity

*The numerator reflects FFO before interest paid; the denominator reflects interest expense.

Table 5 Glossary Of Terms

Term	Definition
Capital	Debt, plus noncurrent deferred taxes, plus equity.
Capital expenditures (capex)	Funds expended to acquire or develop tangible and certain intangible assets. It includes the cost of acquisition of assets through leases and similar arrangements, and excludes capitalized costs that we expense as an analytical adjustment.
Cash flow from operations	This measure reflects cash flows from operating activities, not investment and financing activities. It includes interest received and paid, dividends received, and taxes paid in the period. Additionally, for some items such as postretirement benefits and asset retirement obligations, we include the (net) cost for the period rather than actual cash outflows, in order to separate what we view as financing of these obligations from the operating cost component.

Table 5 Glossary Of Terms (continued)

Term	Definition
Debt	Total short- and long-term borrowings of the company (including maturities), adjusted by adding a variety of on- and off-balance sheet financing arrangements pursuant to our adjustment methodology, and subtracting surplus cash, where applicable. Borrowings are measured at amortized cost (including remeasurement upon change in ownership of the issuer). Foreign-currency unhedged borrowings are measured at each period-end spot rate.
Discretionary cash flow	Cash flow from operations minus capex, minus dividends paid.
Dividends	Dividends paid to common and preferred shareholders and to minority interest shareholders of consolidated subsidiaries.
EBIT	A traditional view of profit that factors in capital intensity. However, it also includes interest income, the company's share of equity earnings of associates and joint ventures, and other recurring, non-operating items.
EBITDA	Operating profits before interest income, interest expense, income taxes, depreciation, amortization, and asset impairment. Excludes undistributed equity earnings of affiliates. While at times EBITDA is considered a proxy for cash earnings, changes in accounting make this increasingly an accrual-based earnings measure. The difference between EBITDA and operating income before depreciation and amortization is in the adjustments we make for operating leases, exploration expense, and stock-based compensation. Exploration expense is added back to EBITDA, rather than being treated as an operating cost. The operating lease adjustment to EBITDA increases for the implicit interest component of rent expense, but not for the depreciation component. Finally, the charge to earnings for share-based compensation is reversed in calculating EBITDA.
Equity	Common equity and equity hybrids, and minority interest.
Equity hybrids	The portion of hybrid instruments attributed to equity pursuant to our methodology for classifying such securities.
FOCF	Cash flow from operations minus capex.
FFO	Operating profits from continuing operations, after tax, plus depreciation and amortization, plus deferred income tax, plus other major recurring noncash items.
Interest	The gross amount of interest incurred (including amounts capital ized), adjusted for charges related to items that we add to debt; no subtraction of interest income, except where derived from assets structurally linked to a borrowing.
Net cash flow	FFO minus dividends.
Operating income before depreciation & amortization	A measure of operating profitability that excludes depreciation and amortization, to partly neutralize capital intensity as a factor when comparing the profitability of companies.
Revenues	Total sales and other revenues we consider to be operating.

Incorporating Adjustments Into The Analytical Process

Our analysis of financial statements begins with a review of accounting characteristics to determine whether ratios and statistics derived from the statements adequately measure a company's performance and position relative to both its direct peer group and the larger universe of industrial companies. To the extent possible, our analytical adjustments are made to better reflect reality and to minimize differences among companies.

Our approach to adjustments is meant to modify measures used in the analysis, rather than fully recast the entire set of financial statements. Further, it often may be preferable or more practical to adjust separate parts of the financial statements in different ways. For example, while stock-options expense represents a cost of doing business that must be considered as part of our profitability analysis, fully recasting the cash implications associated with their grant on operating cash flows is neither practical nor feasible, given repurchases and complexities associated with tax laws driving the deduction timing. Similarly, the analyst may prefer to derive profitability measures from LIFO-based inventory accounting—while retaining FIFO-based measures when looking at the valuation of balance sheet assets.

Certain adjustments are routine, as they apply to many of our issuers for all periods (e.g., operating lease, securitizations, and pension-related adjustments). Other adjustments are made on a specific industry basis (e.g., adjustments made to reflect asset retirement obligations of regulated utilities and volumetric production payments of oil and gas producing companies).

Beyond that, we encourage use of nonstandard adjustments that promote the objectives outlined above. Individual situations require creative application of analytical techniques—including adjustments—to capture the specific fact pattern and its nuances. For example, retail dealer stock sometimes has the characteristics of manufacturer inventory—notwithstanding its legal sale to the dealer. Subtle differences or changes in the fact pattern (such as financing terms, level of inventory relative to sales, and seasonal variations) would influence the analytical perspective.

We recognize that the use of nonstandard adjustments involves an inherent risk of inconsistency. Also, some of our constituencies want to be able to easily replicate and even anticipate our analysis—and nonstandard adjustments may frustrate that ability. However, for us, the paramount consideration is producing the best possible quality analysis. Sometimes, one must accept the tradeoffs that may be involved in its pursuit.

In many instances, sensitivity analyses and range estimates are more informative than choosing a single number. Accordingly, our analysis at times is expressed in terms of numerical ranges, multiple scenarios, or tolerance levels. Such an approach is critical when evaluating highly discretionary or potentially varied outcomes, where using exact measurement is often impossible, impractical, or even imprudent (e.g., adjusting for a major litigation where there is an equal probability of an adverse or a favorable outcome).

Similarly, in some cases, the analyst must evaluate financial information on an adjusted and an unadjusted basis. For example, most hybrid equity securities fall in a grey area that is hard to appreciate merely by making numerical adjustments. So, while we do employ a standard adjustment that splits the amounts in two, we also prefer that our analysts look at measures that treat these instruments entirely as debt—and entirely as equity.

In any event, adjustments do not always neatly allow one to gain full appreciation of financial risks and rewards. For example, a company that elects to use operating leases for its core assets must be compared with peers that purchase the same assets (e.g., retail stores), and our lease adjustment helps in this respect. But we also recognize the flexibility associated with the leases in the event of potential downsizing, and would not treat the company identically with peers that exhibit identical numbers. Likewise, in a receivable securitization, while the sale of the receivables to the securitization vehicle generally shifts some of the risks, often the predominant share remains with the issuer. Beyond adjusting to incorporate the assets and related debt of the securitization vehicles, analysts must appreciate the funding flexibility and efficiencies related to these vehicles and the limited risk transference that may pertain.

Apart from their importance to the quantitative aspects of the financial analysis, qualitative conclusions regarding the company's financial data can also influence other aspects of the analysis—including the assessment of management, financial policy and internal controls.

Communicating our adjustments and related criteria

We traditionally have incorporated analytical adjustments to the ratings process. Our published key ratio statistics are also adjusted to reflect many of the adjustments made.

Since 2003, we have published accounting sections that outline our view of the issuer's accounting characteristics, including the underlying considerations and key adjustments made in our published industrial companies' issuer reports. The purpose is to capture in one place the major accounting issues that affect an issuer's financials, their related analytical significance, and the adjustments made; it is not intended to be a summary of every accounting policy.

We provide a reconciliation table in our credit analysis reports on corporate issuers *(See "New Reconciliation Table Shows Standard & Poor's Adjustments To Company Reported Amounts," published Oct. 3, 2006, on Ratings Direct).* It is a bridge between a company's reported amounts and various Standard & Poor's adjusted measures. The reconciliation table begins with company reported amounts for a range of balance sheet, earnings, and cash flow measures, then lists adjustments to each measure by topic and our total adjusted measure. Not all adjustments are included as of yet in these reconciliation tables. We are modifying our software to incorporate additional adjustments—but some adjustments may not be included, as they do not lend themselves to precision or standardization (e.g., litigation or other contingencies).

Occasionally, adjustments are based in whole or in part on nonpublic information provided to us during the rating process. Our rating analysis, evaluation, and commentary incorporate consideration of this information, but our published data refer exclusively to publicly available information.

Our criteria governing financial-statement adjustments are subject to ongoing review and occasional revisions necessary to address changes in accounting rules and in response to emerging financial products and structures—consistent with our broad objective of maintaining a dynamic criteria framework capable of addressing evolving market conditions in a timely and comprehensive manner.

When considering significant criteria changes (including ratio adjustments), we solicit public input and comments. In addition, we encourage ongoing dialogue with market participants regarding all criteria matters. We regard this dialogue as an important facet of maintaining a robust criteria framework, responsive to the needs of those who use our ratings and other market participants.

Encyclopedia Of Analytical Adjustments

The following sections outline the specific adjustments we use in analyzing industrial companies. At the end, we include our key ratios and their definitions. The list of adjustments, in alphabetical order, includes:

- Accrued Interest And Dividends
- Asset Retirement Obligations
- Capitalized Development Costs
- Capitalized Interest
- Captive Finance Operations
- Exploration Costs
- Foreign Currency Exchange Gains/Losses
- Guarantees
- Hybrid Instruments
- LIFO/FIFO: Inventory Accounting Methods
- Litigation
- Nonrecourse Debt Of Affiliates (Scope Of Consolidation)
- Nonrecurring Items/Non-core Activities
- Operating Leases
- Postretirement Employee Benefits/Deferred Compensation
- Power Purchase Agreements
- Share-Based Compensation Expense

- Stranded Costs Securitizations Of Regulated Utilities
- Surplus Cash
- Trade Receivables Securitizations
- Volumetric Production Payment
- Workers Compensation/Self Insurance

Accrued interest and dividends

Accrued interest that is not already included in reported debt is reclassified as debt. This adjustment allows more consistent comparisons of companies' financial obligations, by eliminating differences arising from the frequency of payments—for example, quarterly, rather than annually—or calendar dates of specific payments—for example, January 1 or December 31.

In a similar vein, accrued dividends on hybrid equity securities are treated as debt, irrespective of the extent of the securities' equity content. (Deferred amounts—whether the deferral was optional or mandatory—are also usually treated as debt, given the need to pay them in a relatively short time. Obviously, we would not include amounts that are noncumulative, which never will be paid.)

Adjustment procedures

- Balance sheet: Accrued interest and dividends accrued on hybrid securities are reclassified as debt. There is no adjustment needed to equity.
- Cash flow statement: Because the impact usually is quite limited, no adjustment is performed to FFO or OCF. Annual cash flow is not affected by payment frequency or dates, except in the year a particular security is issued or retired.

Asset retirement obligations

We treat asset retirement obligations (AROs) as debt-like liabilities. AROs are legal commitments, assumed when commissioning or operating long-lived assets, to incur restoration and removal costs for disposing, dismantling or decommissioning those assets. Examples include the costs of plugging and dismantling on-and off-shore oil and gas facilities; decommissioning nuclear power plants and recycling or storing used nuclear fuel; and capping mining and waste-disposal sites.

These commitments are independent from the level and timing of any cash flow generated by the use of the assets. In certain instances, we expect ARO costs to be reimbursed to the entity through rates or assumed by other parties. When the asset operator's costs are reimbursed by the government or via a rate-setting process, the entity bears far different and less open-ended economic risks—and may not require debt imputation. We have tended to view AROs related to nuclear power plants of rate-regulated U.S. utilities in this light.

Several characteristics distinguish AROs from conventional debt, including timing and measurement uncertainties; tax implications; and the standing of claimants in bankruptcy.

ARO measurement involves a high degree of subjectivity and measurement imprecision. Our starting point is the reported liability amount, which may be adjusted for anticipated reimbursements, asset salvage value, and tax reductions, further adjusted for any assumptions we view as unrealistic.

Most AROs involve obligations to incur costs that may extend well into the future. Uncertainties inherent in their estimation include:

- The amount of the ultimate cost of abandonment, which will depend on the relevant country's laws and asset-specific environmental regulations at retirement; the condition of the markets for the specific assets' retirement services; possible economies of scale for the operator; and whether the activities ultimately are performed by the operator or by a third party.
- The timing of asset retirement, which is subject to assumptions that can change materially. For example, in extractive projects, future price expectations for hydrocarbon or minerals affect the economic life of the assets. For power generators, asset-retirement timing depends notably on local regulatory decisions. Their impact might be favorable (i.e., in the case of an operating license extension) or unfavorable (i.e., in the case of an early mandated closure).
- The discount rate to be used in the present value calculation. U.S. GAAP requires the use of an entity-specific discount rate. Hence, the stronger the entity's credit, the lower the discount rate—and the higher the

liability. Similarly, the periodic accretion rate is lower for stronger credits, and higher for weaker credits. If nothing else, this hinders comparability across companies using U.S. GAAP, as well as to IFRS-reporting companies, which use market-related rates adjusted to risk-specific factors attributable to the liability.

AROs are recorded on a pretax basis under most accounting standards. Any expected tax benefits generally are reflected as a separate deferred tax asset on the balance sheet (because the ARO-related asset is depreciated). Tax savings, when they coincide with the ARO payments (as opposed to their provisioning), reduce the net cash cost, which we factor in our analysis to the extent we expect the company to generate taxable income in the particular jurisdiction.

- The obligation, net of any dedicated retirement-fund assets, salvage value, and anticipated tax savings, is added to debt. We generally adjust for the net aggregate funding position, even if some specific obligations are underfunded and others are overfunded.
- Adjustments are made on a tax-effected basis in cases where it is likely the company will be able to use the deductions.
- The accretion of the obligation reflects the time value of money and is akin to non-cash interest—similar to postretirement benefit (PRB) interest charges. Accordingly, we reclassify it (net of earnings on any dedicated funds, if applicable—but never less than zero) as interest expense for both income-statement and cash-flow statement analysis. We keep the net present value of the obligations newly incurred during the period (analogous to PRB service costs) within operating expenses. If dedicated funding is in place and the related returns are not entirely reflected in reported earnings and cash flows, the unrecognized portion of the return on these assets is added and the recognized portion is reclassified to interest expense and operating cash flow.
- Cash payments for abandonment and contributions into dedicated funds that exceed/are less than the sum of: newly incurred obligations plus accretion of existing obligations are reclassified as repayment/incurrence of a debt obligation; this increases/decreases operating cash flow and funds from operations by the difference.
- For U.S. rate-regulated utilities that own nuclear power plants included in rate base, we have concluded that the decommissioning liability should not be viewed as a debt-equivalent liability. This is because of the safeguards that ensure funding sufficiency and collection of decommissioning costs in rates. Funding through customer rates and the probable nature of recovery result in a substantive liability defeasance.

Adjustment procedures

Data requirements

- The estimated asset retirement obligation (ARO), based on financial statement disclosure or analyst estimate.
- Any associated assets or funds set aside for the ARO.
- ARO interest costs, whether charged to operating or financing costs.
- New provisions (increases in liability during the period).
- Gain or loss on assets set aside for funding.
- Cash payments for AROs.

Calculations

- Subtract assets set aside to fund asset-retirement liabilities from the ARO to create a net ARO.
- Multiply this net obligation by (1 - the tax rate) to derive ARO adjustment for debt.
- Subtract both the gain (loss) on assets set aside from the sum of new provisions and interest costs and compare this amount to the cash payments made to arrive at the excess contribution/shortfall.
- Multiply this excess contribution/shortfall by (1 - the tax rate) to arrive at the ARO adjustments to funds from operations and cash flow from operations.

Procedures

- ARO debt is added to reported debt.
- ARO interest costs (net of ARO fund earnings) are removed from operating expenses, if they are included in these, and added to interest expense.
- The ARO adjustment to FFO is added to FFO.

(Please see "Asset Retirement Obligations: How SFAS 143 Affects U.S. Utilities Owning Nuclear Plants," published March 31, 2004, and "Corporate Ratings Criteria, 2006 edition—Corporate Asset-Retirement Obligations," on RatingsDirect.)

Capitalized development costs

Costs relating to the conceptual formulation and design of products for sale or lease commonly are expensed on the income statement—while costs incurred subsequent to establishing the technological feasibility of these products are capitalized. The asset is then amortized over its estimated economic life.

Defining feasibility involves substantial subjectivity. Accordingly, the treatment of product or asset development costs sometimes varies substantially among companies or accounting regimes. For example, many U.S. software companies do not capitalize any software development costs (an analytically conservative approach), while others capitalize certain expenditures and amortize them over future periods.

Expensing, rather than capitalizing, can have a meaningful impact on a company's financial statements and credit metrics, making peer comparisons difficult. Automaker accounting for tooling poses similar comparability issues relating to varying capitalization policies.

While it is acceptable under the applicable accounting rules for a company to capitalize certain development costs, in order to facilitate comparability, we adjust reported financial statements. The amounts capitalized are treated as if they had been expensed. To the extent that the amortization of past capitalization equals current development spending, there is no impact on operating expenses, operating profit, or EBIT, but there is an impact on EBITDA and operating profit before depreciation.

This approach helps make companies' operating performance more transparent and comparable, regardless of their stance on capitalizing software and similar development costs. Note, that with respect to energy exploration costs, we take the opposite approach *(see adjustment for exploration costs)*, given the objective of comparability with most companies in that industry and the pragmatic aspects of doing so.

A company's position in its product life cycle has a great effect on its current spending relative to the amortization of past capitalization of development costs. However, as a practical matter—in the absence of more accurate figures—we use the annual amortization figure reported in the financial statements as a proxy for the current year's development costs. We realize, too, that the amount amortized is not entirely comparable across companies, as the amortization period for these assets may vary. For example, in the case of software, it typically ranges from two to five years.

Adjustment procedures

Data requirements

- Amount of development costs incurred and capitalized during the period.
- Amount of amortization of relevant capitalized costs.

Calculations

- EBITDA, operating profit before depreciation, and capital expenditures: subtract the amount of net capitalized development costs, or, alternatively, the amortization amount for that period.
- EBIT and operating profit after depreciation: subtract (or add, as the case may be) the difference between the spending and amortization in the period.
- FFO and capital expenditures: Subtract the amount capitalized in the period.
- Balance sheet accounts: We do not carry through the adjustment to the cumulative asset (and equity) accounts, weighing the complexity of such adjustments against the limited impact that can be expected in most cases on amounts that are secondary to our analysis.

(Please see "Accounting Issues In The U.S. High Technology Group," published Jan. 3, 2007, on RatingsDirect.)

Capitalized interest

We factor in capitalized interest as expense in the period when incurred. The valuation of property, plant, and equipment (PP&E) includes, under some GAAP, a cost of carry element relating to multi-period project expenditures. Part of the rationale is that the company must factor the carrying costs when deciding on a project's economics, but this obscures the amount that actually must be paid during the period. Companies may also have significant discretion with respect to the amounts they capitalize, making comparisons difficult. Accordingly, we prefer to focus on total interest cost.

As a result, we reverse interest capitalization and include the amount as an expense. In the cash flow statement, we reclassify capitalized interest from investing to operating cash flow. This correspondingly reduces funds from operations and capital expenditure amounts. Free cash flow remains unchanged.

We do not adjust for the cumulative gross-up of PP&E resulting from interest capitalization, tax effects, or future depreciation effects. That is, we do not try to identify the portion of PP&E attributable to past interest capitalization, in order to reduce PP&E by the amount that would correspond to the expensed view taken on such interest capitalized in the past. It would be impractical to attempt to do so, given the lack of data available. Moreover, the more material impact tends to be to coverage and profitability measures, not to asset or equity-based ratios.

Adjustment procedures

Data requirements

- The amount of capitalized interest during the period.

Calculations

- Interest expense: add amount of capitalized interest; and
- Capital expenditures, FFO, and operating cash flows: reduce by amount of capitalized interest that is reclassified as operating cash flows.

Captive finance operations

A captive finance operation (captive) functions primarily as an extension of a company's marketing activities. The captive facilitates the sale of goods or services by providing financing (in the form of loans or leases) to the company's dealers and/or end customers. The captive can be structured as a legally separate subsidiary, or as a distinct operating division or business line of the company. Captive finance units organized as separate subsidiaries are rated the same as their parents in the overwhelming majority of cases, meaning we view their default risk as indistinguishable from that of the parent.

Whatever the legal/organizational structure, the two businesses are not analyzed on a consolidated basis. Rather, we segregate financing activities from corporate/industrial activities and analyze each separately, reflecting the differences in business dynamics and economic characteristics, and the appropriateness of different financial measures. Our approach is to create a pro forma captive unit to enable finance-company analytical techniques to be applied to the captive finance activity, and correspondingly appropriate analytical techniques to the pure industrial company.

Finance assets (e.g., loans receivable and leases)—along with appropriate amounts of financial debt and equity—are allocated to the pro forma finance company; all other assets and liabilities are included in the parent/industrial balance sheet. Similarly, only finance-related revenues and expenses are included in the pro forma finance company income statement. The debt and equity of the parents and the captives are apportioned so that both entities will reflect, in most cases, identical credit quality.

In our analytical methodology for captive finance operations, we attribute debt and equity to the pro forma finance company based on our assessment of the quality of the finance assets, taking account of factors such as underwriting standards, charge-off policy, quality of the collateral, and portfolio concentration or diversity. The adjusted financial measures are highly sensitive to assumptions we make about the leverage appropriate to the finance assets in question. We continue to refine our leverage guidelines for major finance asset types.

Adjustment procedures

Note: In almost all instances, financial statements fully consolidate majority-owned captive finance operations: Here, consolidated financial statements are assumed as the starting point. Where separate financial statements are also available for the finance unit, information from these can be used to refine the adjustment.

Data requirements

- On-balance-sheet finance receivables and leases, net;
- Finance receivables and leases sold or securitized—carried off-balance-sheet;
- Finance company revenues (if actual finance revenues are unavailable, we use 15% of total finance receivables);
- Finance company administrative expenses (if actual finance company expenses are unavailable, we use 3% of total finance receivables);
- Debt to equity ratio: determined to reflect our view of the "leveragability" of the captive's assets (on- and off-balance-sheet finance receivables and leases);
- Interest rate (the average rate experienced by the company); and
- Required fixed charge coverage—an interest coverage appropriate for the rating. (Often, 1.25x is used.)

Calculations

- Total finance assets = on-balance-sheet finance receivables and leases + finance receivables and leases sold or securitized (carried off-balance-sheet).
- Finance company EBIT = finance company revenues – noninterest expenses.
- Finance company debt = Total finance assets times the debt-to-equity ratio/(1 + debt-to-equity ratio). This can never be more than reported consolidated debt; if so, the debt to equity ratio should be adjusted. (Separately, consolidated debt also is adjusted to reflect the debt equivalent of securitized assets and hybrid securities.)
- Finance company equity = total finance assets – finance company debt.
- Finance company interest = most recent two-year finance company debt x interest rate.
- Finance company required EBIT = finance company interest x required fixed charge coverage.
- Transfer payment = finance company EBIT – finance company required EBIT (which can be positive or negative).
- Subtract finance company revenues from total revenues to derive adjusted industrial company revenues.
- Subtract finance company operating expenses, including depreciation, from total operating expenses to derive adjusted industrial company operating expenses.
- Industrial EBIT = adjusted revenues – adjusted expenses + transfer payment.
- Reduce reported interest by finance company interest, if reported captive finance company's interest is included in consolidated operating expenses; otherwise, no adjustment is required.
- Reduce reported debt (adjusted for securitized assets) by finance company debt.
- Reduce reported equity by finance company equity (after increasing total reported equity by the minority interests in the captive finance company's equity, if the captive is not fully owned, and its reported equity excludes minority interests).
- Remove the finance company's cash flows, including capital expenditures, from reported cash flows.

(Please see "Criteria: Request for Comment: Risk-Based Framework for Assessing the Capital Adequacy of Financial Institutions," published Jan. 12, 2007; "Criteria: Captive Finance Operations," published April 17, 2007; and Finance Subsidiaries' Rating Link To Parent, in "Corporate Ratings Criteria 2006" edition, on RatingsDirect.

Exploration costs

Under some accounting systems, oil and gas exploration and production (E&P) companies may choose between two alternative accounting methods, full cost and successful efforts. These accounting methods differ in what costs these companies capitalize or expense. A successful-efforts-reporting company expenses the costs of unsuccessful exploration drilling (dry-hole costs) and exploration costs, such as geologic and geophysical expenditures (seismic surveys) and the costs of carrying and retaining undeveloped properties. In successful-efforts accounting, only exploratory drilling costs that result in the discovery and development of a commercial oil and gas field may be capitalized and amortized based on the field's proved reserves on a unit-of-production basis; all dry-hole expenditures are expensed as incurred. Using the full-cost accounting method, all exploration and development expenditures are capitalized and amortized over the reserves of the related pool of properties.

Another difference is the size of the cost center used to amortize capitalized costs. Successful-efforts companies use smaller cost centers, such as a particular lease or field; full-cost companies generally use larger cost centers, which may be as large as an entire country.

We view successful-efforts accounting as more appropriate, given the highly risky nature of hydrocarbon exploration. Successful-efforts accounting does not have the potential to inflate equity and smooth earnings to the same degree as full-cost accounting. In general, large companies (e.g., major integrated companies) use the successful-efforts method, while smaller companies (e.g., independent E&P companies) use the full-cost system.

However, our analysis of exploration costs requires making comparisons between companies that use different accounting methods, which can best be accomplished by adding back exploration expense to EBITDA for successful-effort companies. (While we prefer the successful efforts approach, there is no practical way to adjust full cost users to a successful efforts method.) Exploration expense usually is disclosed on the face of the income statement of successful efforts companies. This number often is referred to as EBITDAX.

Given our preference for successful efforts, we limit this adjustment to EBITDA measures—and do not carry the adjustment through to all related accounts or to other ratios. Adjusting EBITDA usually suffices for comparative purposes. And, adjusting a successful efforts company's balance sheet to reflect what it would look like if it had used the full-cost method—or vice versa—is not really feasible. (Apart from the differences as to what companies can capitalize under the two methods, the rules for asset impairment tests also differ. The full-cost impairment test, called the ceiling test, generally is easier to violate because of higher asset carrying costs and its trigger mechanism. (If the book value of assets falls below the discounted present value of cash flows, a charge may be necessary. The trigger for ordinary impairment is related to the undiscounted future cash flows.)

Adjustment procedures

Data requirements

- Exploration expenses (only applies to E&P companies using the successful-efforts method of accounting).

Calculations

- Adjustment to operating income before depreciation, depletion, and amortization to calculate EBITDA: We add exploration expense back to operating income before depreciation, depletion, and amortization in the EBITDA calculation. This increases EBITDA and operating income before D&A by the entire amount of exploration expense.

(Please see "Credit FAQ: Exploring Standard & Poor's Oil And Gas Company Reconciliation Tables," published Feb. 12, 2007, on RatingsDirect.)

Foreign currency exchange gains/losses

Foreign currency exchange gains/losses can be related to transactions or translations:

- Transaction gains/losses arise from transactions that are denominated in a currency other than the entity's functional currency (generally the currency in which the entity principally transacts). Examples include buying and selling goods or services whose prices are denominated in a foreign currency, borrowing or lending in a foreign currency, or other contractual obligations denominated in a foreign currency. A change in the exchange rate will increase or decrease the amount of functional currency needed to settle the account between the time the transaction is recorded in the functional-currency accounts and the time it is settled, leading to exchange gains or losses. When translating the related accounts (e.g., loans receivable, accounts payable, and debt) into the reporting currency, such gains and losses are recognized in the income statement as incurred.

- Translation gains/losses occur when translating financial statements of a subsidiary from a local currency to the reporting currency of the enterprise for consolidation. Translation gains or losses are included in shareholders' equity (under U.S. GAAP, included in other comprehensive income for the period and in accumulated other comprehensive income in the owners' equity section of the balance sheet).

Foreign currency transaction gains/losses recognized in the income statement raise questions similar to those in Nonrecurring Items/Noncore Activity *(see below)*. To present a representative view of operating performance and financial ratios, we typically adjust company income statements to exclude nonrecurring and other unusual transaction gains and losses.

Currency transaction gains and losses may be viewed as recurring or nonrecurring. We review transaction gains and losses and determine whether or not to adjust for them. We may adjust reported financial results for currency gains and losses that result from one-time or infrequent transactions; for example, we may adjust (or exclude) foreign currency gains or losses resulting from the infrequent purchase of a specialized capital asset payable in a foreign currency.

When the gains or losses result from recurring or ongoing transactions, we do not adjust. We consider transaction gains and losses as ongoing when the company has a history of entering into transactions denominated in foreign currencies. The purchase of inventory that is paid in a foreign currency is an example. Debt denominated in a foreign currency could also result in recurring foreign currency gains and losses that we would not adjust for.

Companies may not report currency gains or losses separately for recurring and nonrecurring transactions. Consequently, we may not make adjustments if the data are not available, or if the amount is immaterial. Our analysis must also take into account the potential for changes in actual cash flows that may be required to settle a transaction denominated in a foreign currency.

Translation gains/losses are not included in determining net income, but are included in shareholders equity (and, under U.S. GAAP, in other comprehensive income) as mentioned above. Companies generally translate assets and liabilities using the exchange rate at the balance sheet date. The income statement is translated at the exchange rate in effect at the time revenues, expenses, gains and losses are recognized. The cash flow statement is translated using the exchange rate in effect at the time of the cash flow. As a practical matter, companies often use an average exchange rate for the reporting period for both income and cash flow statements. In addition, the cash flow statement reports the effects of exchange rate changes on cash balances held in foreign currencies on a separate line. We do not adjust the balance sheet, the income statement, or the cash flow statement for translation gains or losses included in other comprehensive income.

If a parent liquidates its investment in a foreign subsidiary (or investment), the amount of foreign currency gains or losses built up in equity are removed from equity and included in net income for the period. This amount should be excluded from income as a nonrecurring item (as would generally apply to the gain or loss resulting from the sale).

Adjustment procedures

Data requirements

- Amounts of nonrecurring (analytically determined) foreign currency exchange transaction gains and losses.

Calculations

- The amount of nonrecurring foreign currency gain or loss is added to or subtracted from operating income before and after D&A, EBITDA, and EBIT.

Guarantees

The accounting for guarantees can vary greatly. In many instances, a guarantee to support borrowings of unconsolidated affiliates or third parties is not recorded on the guarantor's consolidated balance sheet until it meets certain tests regarding probability of payment.

Alternatively, it may be recorded at the lowest amount in a range of possible outcomes or at a statistically calculated expected value (e.g., under IFRS, a contingent obligation may be measured at a probability-weighted figure of potential payment amounts). To illustrate, if the company estimates a 70% chance of having to pay nothing and a 30% chance of having to pay €1 million, then the company obligation would be measured at €300,000, an amount that has no probability of being paid.

We may take a different approach, to reflect our own assessment of the risk of ultimately being required to pay (upon the default of the other party).

We add the guaranteed amount to the guarantor's total debt, unless the other party is sufficiently creditworthy (i.e., investment-grade) in its own right, or if we assess the likelihood of payment at a lower amount. (Interest is not imputed on such adjustment items, since the potential obligation may materialize far in the future, and there is no current need to service that potential obligation.)

In the case of an affiliate, we consider the possibility of support for the borrower's debt even absent a formal guarantee.

Performance guarantees are treated differently, because there should be little impact as long as the company maintains its work or product quality. Construction companies often provide performance guarantees as a condition in work contracts.

A company's track record of payments for performance guarantees could be an indicator of the amount of potential future liability. Only if the track record gives us specific reason for concern would we attempt an estimate of the liability—and add that amount to debt for ratio calculations.

Adjustment procedures

Data requirements

- Determine the value of the guarantees on and off the balance sheet to be added to debt, net of tax benefit, as applicable.

Calculations

- Debt: Add the amount of off-balance-sheet debt-equivalent; reclassify as debt the amount of on-balance-sheet liability.
- Equity: Subtract amount of off-balance-sheet debt-equivalent.

Hybrid instruments

Hybrid instruments have some characteristics of debt, and some of common equity. The more weight the latter carries, the more equity content we attribute to the instrument. We classify corporate hybrids' equity content as minimal, intermediate, or high.

How to reflect hybrids in credit ratios is not a simple question. For many years, we did not divide the amounts involved in proportion to the equity content of the specific security, believing the resulting numbers could be misleading. As an example, a company might pay the stipulated periodic amount or defer it; under no scenario would it defer a fraction of the payment: Therefore, calculating a fixed-charge coverage ratio with a fractional amount has little intuitive meaning.

For hybrids with intermediate equity content, we instead computed financial ratios both ways—viewed alternatively, as debt and as equity. Two sets of coverage ratios were calculated—to display deferrable ongoing payments (whether technically dividends or interest) entirely as ordinary interest and, alternatively, as an equity dividend. Similarly, two sets of balance-sheet ratios were calculated for the principal amount of the hybrid instruments, displaying those amounts entirely as debt and entirely as equity.

For hybrids, analytical truth lies somewhere between these two perspectives, and analysts have been—and are—encouraged to continue viewing hybrids from all perspectives—i.e., computing ratios with the security as debt and, alternatively, as equity; to interpolate between the sets of ratios to arrive at the most meaningful depiction of an issuer's financial profile; and note and give effect to each more-equity-like or less-equity-like feature of various hybrids in the same category, although such nuances play, at most, a very subtle role in the overall rating analysis.

However, we changed our methodology in 2006 because it proved too challenging to communicate our previous, more abstract approach—and issuers, in particular, had trouble appreciating the potential impact on our view of their financial profile. Notwithstanding the issues mentioned above, we adopted the following adjustments (after adjusting convertible debt issued by IFRS reporting companies as described below):

- For hybrids in the intermediate category, we calculate ratios with outstanding amounts (excluding unpaid accrued remunerations) split 50-50: One-half of the principal is categorized as debt and one-half as equity; one-half of the period payments is treated as common dividends and one-half as interest. (There is no adjustment to taxes.) This set of ratios is used as the basic adjusted measures, and these are the ratios we publish.

- Hybrids with minimal equity content are treated entirely as debt for calculating ratios.
- Hybrids with high equity content are treated entirely as equity for calculating ratios.
- Unpaid dividends that have accrued, prior to period end, are viewed as debt—even for equity-like securities.

Convertible debt is not treated as a hybrid—unless the conversion is mandatory, or it features appropriate tenor, subordination, and deferability characteristics. While IFRS and other accounting regimes split the issued value of a convertible debt obligation between its pure debt component (the fair value of a similar debt obligation without the conversion feature), accounted for as debt, and the embedded conversion feature (the difference between the debt component and the issue price), accounted for as equity, such convertible debt generally does not attract any equity credit in our methodology. Rather, we adjust reported debt by the value of the conversion option included in shareholders' equity. Cash-based measures such as FFO continue to reflect only the actual cash cost of the convertible debt, based on the coupon rate.

Adjustment procedures

Data requirements

- Amount of hybrid instrument in the balance sheet and shareholders' equity;
- Amount of associated expense and payments in the period; and
- Amounts of accrued unpaid interest/ dividends.

Calculations

- A high-equity-content hybrid reported as equity is treated as reported, as are its associated dividends. However, accrued dividends are included as debt.
- A high equity content hybrid reported as debt is removed from debt and added to equity. The associated interest charge is removed from interest expense and treated as a dividend. Additionally, interest payments are also adjusted as dividends in the FFO and operating cash flow calculations.
- An intermediate equity content hybrid reported as equity (e.g., preferred stock) has 50% of its value removed from equity and added to debt. Also, 50% of the dividend amount is removed and added to interest expense and interest paid, impacting the FFO and OCF calculations.
- An intermediate equity content hybrid reported as debt has 50% of its value removed from debt and added to equity. Also, 50% of the associated interest is removed from interest expense and interest paid and added to dividends.
- A minimal equity content hybrid reported as equity is removed from equity and added to debt. Its associated dividends are added to interest expense and interest paid, thereby also reducing FFO and OCF.
- A minimal equity content hybrid reported as debt is treated as reported, as is its associated interest.
- The accrued unpaid charges on hybrid instruments are categorized as debt.

Note: For optionally convertible instruments, prior to the reclassifications above, we recombine the instrument's issued amount (amortized cost) if it has been bifurcated (as described above, notably for IFRS-reporting companies). We also adjust the period's expense, where necessary and practicable, to equal the instrument's debt component multiplied by the company's refinancing rate, at the convertible's issuance date, for the equivalent nonconvertible instrument.

(Please see "Criteria: Equity Credit For Corporate Hybrid Securities, published May 8, 2006, on RatingsDirect;" "Criteria: Clarification Regarding Step-Ups Used In Equity Hybrids, Aug. 9, 2007; and "Criteria: Standard & Poor's Announces Several Refinements To Its Hybrid Capital Criteria," Oct. 30, 2007.)

LIFO/FIFO: Inventory accounting methods

The choice of inventory accounting methods under U.S. GAAP between first-in, first-out (FIFO); last-in, first-out (LIFO); weighted average; and specific identification can provide dramatically different results for peers that engage in the same underlying activities. This issue is more pronounced in sectors that are inventory-intensive, and in particular, where inventory prices fluctuate significantly.

The challenge of comparing peers increases on a global dimension. Similar choice of accounting options exists in generally accepted accounting standards other than U.S. GAAP—while LIFO, widely used in the U.S., is not permissible under many other accounting standards, including IFRS. Tax treatment of permissible inventory costing methods is a key driver in management's decision to elect a method, and varies significantly by jurisdiction. (For example, LIFO is permitted for tax-reporting purposes in the U.S., and those who elect LIFO for tax purposes must also use it for their financial statement reporting.)

Moreover, some companies use a combination of costing methods. For example, management may elect to use the LIFO method for a portion of inventory in which prices are expected to rise and FIFO for the balance. In other instances, inventory reported on a consolidated financial statement can include inventory balances of subsidiaries in different countries, each of which use different accounting methods.

The greatest potential disparity of financial results is between FIFO and LIFO accounting methods. In a period of rising prices, the LIFO method results in a lower income than FIFO, because the most recent costs flow into cost of goods sold on the income statement, and the oldest costs are reflected in inventory on the balance sheet. Furthermore, cash flows are temporarily improved, because current income taxes are lower as a result of the lower income. Apart from intercompany comparisons, different methods can skew the perspective of corporate performance. For example, LIFO provides a better reflection of matching costs against revenues on the income statement, but creates a balance-sheet distortion by having older costs residing in inventory. The FIFO method, on the other hand, provides a more current valuation of inventory on the balance sheet, but can significantly understate cost of goods sold in a period of rising prices, resulting in artificially overstated income.

- Balance sheet: Where significant to our analytical process or essential for peer comparability, we add back the LIFO reserve to inventory amounts on the balance sheet for companies that use the LIFO method. This enables us to reflect inventory balances at approximate current market value. (Companies that apply the LIFO method are required to disclose what the inventory valuation would be under FIFO, through an account called the LIFO reserve, which represents the cumulative effect on gross profit from the use of the LIFO method.) A corresponding adjustment, net of tax, is made to equity.
- Income statement: We do not adjust the income statement when companies use LIFO, believing the LIFO method results in costs of goods sold that are more indicative of replacement-cost values, and the best matching to revenues. While it might be desirable to adjust for those companies that use FIFO or average costs methods, the data generally are unavailable.
- When a company using the LIFO method has inventory balances that decrease over a period of time, LIFO liquidation may result. It means that older, less-recent layers of inventory are turned into cost of goods sold as a result. (These are older in terms of their accounting, not necessarily in any physical sense.) Assuming an inflationary environment, cost of goods sold is reduced, and as a result, income increases because of LIFO liquidation gains. To capture the true sustainable profitability of a company, the gains generated from LIFO liquidation generally are excluded from our current profitability measures and ratios.
- Cash flows: We typically do not adjust the cash flows, but we consider, qualitatively, the boost to cash flows the LIFO method affords during periods of price inflation (via taxes deferred to future periods).

Adjustment procedures

Data requirements

- For the balance-sheet adjustments: LIFO reserve.

- For the income statement adjustments: LIFO liquidation gains.

Calculations

The balance sheet adjustments affect inventory (assets) and equity.

- LIFO reserve is added to inventory (assets).
- Equity is increased by the LIFO reserve (after-tax).

The income statement adjustment affects operating income before and after D&A, and EBITDA and EBIT.

- LIFO liquidation gains are deducted from operating income when calculating operating income before and after D&A, and EBITDA and EBIT.

Litigation

We make case-by-case judgments regarding the probability of a negative outcome, the potential financial effect, and its timing, including duration of any appeals process. We also regularly obtain additional data from the company involved, on a confidential basis, to enable a more meaningful analysis of plausible scenarios. These might include any available legal opinions and research; the company's legal strategy; and the number, size, and status of claims. To assist us, we may consult legal counsel to evaluate likely scenarios. This includes in-house legal staff, external counsel, and/or industry-related counsel.

To the extent that a monetary judgment is predictable, we size the amount that will be paid and treat it as a debt-equivalent. If payment is not imminent—if, for example, there is an extended appeals process—we would estimate the time until actual payment, and discount the eventual payment amount unless interest will be added. The adjusted debt ratios are calculated including the present value of the estimated payout, on an after-tax basis. Where applicable, we subtract any expected insurance recoveries.

It usually is very challenging to size litigation outcomes. Previous cases of similar nature can serve as benchmarks. Subjective judgments regarding the merits of a case may also inform our view of possible outcomes.

Sometimes, the company's litigation reserves recorded in its financial statements can offer insight. Companies must reserve for litigation they can quantify. In practice, most companies tend to minimize legal reserves (although some companies—especially European companies—will over-reserve to enable smoothing of future earnings). Therefore, to the extent that a company does reserve, one may ordinarily conclude there is a high likelihood that required payments will be at least that amount. The company's reserve is not a reliable indicator that the ultimate liability will not exceed that amount. In any event, providing reserves is merely an accounting recognition of the liability; it doesn't mean that the company has put aside cash to fund the liability. We would still need to adjust the debt figures to reflect the cash impact that a payment would entail. (On the other hand, there often will be a lengthy period until payment is made, so we also consider the company's ability to generate cash in the interim.)

A class-action suit permits a large number of individual claims to be combined and tried as one lawsuit. We view class-action lawsuits as the most troublesome type for credit quality because of the potential size of awards. Class-action suits must be certified by a court to proceed to trial; however, once certified, the lawsuit often takes years to wind through the litigation process.

Outside the U.S., litigation is less significant as a credit risk than in the U.S. Typically, there is no award of punitive damages, class actions are limited, and/or trials may not come before juries that can react unpredictably to the litigation.

Because the specific financial effect of a lawsuit is difficult to quantify accurately, we may rely on analytical techniques such as calculating ranges of outcomes or performing sensitivity analysis. This can be very helpful if it allows us to conclude, for example, that the company can manage even the more dire potential outcomes without materially affecting its financial profile. Alternatively, if significant uncertainty remains, we might consider a downgrade based on a very large risk exposure.

Litigation poses several important, potentially troubling considerations beyond any direct financial consequences. We consider the potential damage to a company's reputation or ability to conduct normal business operations. For example, product liability cases sometimes result in the product's being removed from the market. Substantial litigation may require an inordinate amount of management time and create quite a distraction from running the business.

More broadly, lawsuits can affect a company's reputation and/or its ability to garner further business or raise capital. Public mistrust and a negative perception of the company's operating strategy would definitely be of concern.

Last, but not least, bonding requirements can pose a tremendous liquidity challenge, especially in jurisdictions that have no bonding caps. Bonding can tie up cash that could otherwise be invested in the business, even if it does not pose an immediate threat to solvency. (Naturally, in the case of litigation expected to benefit the company, similar adjustments apply, in reverse.)

Adjustment procedures

Data requirements

- Determine the value of the litigation exposure to be added to debt.

Calculations

- Debt: Add the amount of debt equivalent (net of tax benefit, as applicable) to debt; and
- Equity: Subtract the amount of off-balance-sheet debt equivalent, net of tax.

(Please see "How Litigation Risk Affects Corporate Ratings," published Nov. 28, 2005, on RatingsDirect.)

Nonrecourse debt of affiliates (scope of consolidation)

In the context of corporate debt analysis, non-recourse debt often refers to a situation in which an affiliate or subsidiary of a company borrows funds, possibly pledging its assets as collateral, while the parent company and other subsidiaries in the corporate structure have no legal obligation to perform under the borrowing agreement. If an event of default occurs, the lender's claims are limited solely to the subsidiary that borrowed the money.

Non-recourse debt may exist for a variety of reasons. A company may want to legally isolate the bankruptcy risk of a subsidiary, for example, because the subsidiary's business prospects are more unpredictable than those of the parent. Also, non-recourse debt may result from a particular jurisdiction's legal requirement to operate locally through a separate legal entity. In other cases, a company may own only a portion of a subsidiary, maybe even a minority interest, and the company may be unwilling to put itself on the hook to fund the obligations of the joint venture.

In non-recourse structures, the parent company has the legal right to walk away from the troubled (or bankrupt) subsidiary. This often is a by-product of corporate law and related legal isolation doctrines related to entities structured as corporations or other limited-liability structures. Notwithstanding the theory, history has shown this often is not the way things play out. The parent company often ends up providing economic support to the subsidiary, despite the non-recourse nature of the obligation.

In analyzing these situations, we attempt to understand the relationship between the parent and subsidiary, and make a judgment about whether the parent would be inclined to step in (and to what extent). While predicting the outcome of such a scenario is not an exact science, we believe that considering plausible scenarios is superior to relying solely on the legal framework, and ignoring the economic relationship extant between the entities.

The relationships between the affiliated entities can vary greatly. The entity issuing the debt considered to be non-recourse may simply represent a non-core, non-strategic investment; if so, the parent is not burdened with the subsidiary's debt obligations.

At the other end of the spectrum, the subsidiary's operations may be characterized as an integrated business. The analysis would then fully consolidate the subsidiary's financial statements, including debt. Furthermore, the risk profile of the subsidiary's operations would be integrated with the overall business risk analysis of its parent.

Often, the subsidiary issuing the debt may not fall neatly into either category; it may lie somewhere in the middle of the spectrum. Sometimes we use a pro rata consolidation to reflect this middle ground. For example, we would apply pro rata consolidation to joint ventures between partners of comparable capacity and willingness to support for their respective strategic reasons. Even in cases that do not call for analytical consolidation, we presume there will be additional investment in the non-recourse entity, i.e., the money the company likely would spend to provide support or bail out the unit in which it invested.

No single factor determines the analytical view of the relationship with the affiliate; rather, several factors, taken together, will lead to one characterization or another, including:

- Strategic importance—integrated lines of business or critical supplier;
- Percentage ownership (current and prospective);
- Management control;
- Shared corporate name;
- Domicile in same country;
- Common sources of capital and lending relationships;
- Financial capacity for providing support;
- Significance of amount of investment;
- Investment relative to amount of debt at the venture or project;
- Nature of any other owners (strategic or financial; financial capacity);
- Management's stated posture;
- Track record of parent company in similar circumstances;
- The nature of potential risks;
- Shared collective bargaining agreements; and
- Jurisdiction's bankruptcy-law regime.

Adjustment procedures

There is no standardized adjustment, given the multiple fact patterns and subjective nature relating to subsidiaries/projects/joint ventures. As explained above, some consolidated entities—and their liabilities—might be deconsolidated, while some nonconsolidated entities may be consolidated.

Another possible adjustment is pro rata consolidation. This approach is not used too frequently, and typically applies only when both owners have similar financial profiles and motivations with respect to a joint venture.

Note that even in cases where we conclude that the liability will not ultimately be supported, we could well expect that the owner would extend partial support to the venture or subsidiary, including additional investments to attempt to rescue it. We would try to size such additional expenditures—and impute that amount as debt to the parent.

(Please see "Corporate Ratings Criteria," 2006 edition: Parent/Subsidiary Links, and "Credit FAQ: Knowing The Investors In A Company's Debt And Equity," published April 4, 2006, on RatingsDirect.)

Nonrecurring items/noncore activities

We typically make adjustments to a company's reported operating income and cash flow to remove items we consider nonrecurring and include those we consider recurring, so the historical financial ratios will be more indicative of future performance. These adjustments cover items including discontinued operations; effects of natural disasters; gains or losses on asset sales and sale/leasebacks; and one-time charges for asset write-downs, restructurings and plant shutdowns.

We review each potential nonrecurring item, and determine whether to adjust for it. Our view of these items may differ from the company's view, as presented in financial statements or footnotes.

We may view some supposedly one-time restructurings as ongoing for a particular company. Taking such a view may reflect a company's history of recurring restructuring charges, or the perceived need to address either company-specific or industry-wide competitive issues (for example, the need to move facilities offshore in order to be cost competitive).

We may also view certain other items that company management characterizes as one-time items as normal operating costs: In the retail industry, we do not typically view inventory write-downs or high store pre-opening costs from a rapid expansion program as unusual items.

In a similar vein, we often distinguish between a company's core business activity and other, ancillary activities—especially if there is some question about the latter's sustainability. A manufacturer may earn money from trading activity; it may even set up its treasury operations as a profit center, but we may isolate, reclassify, and separately analyze the results of those operations.

For income derived from the sale and licensing of corporate assets, we similarly distinguish between sustainable, ongoing sales and those that are more opportunistic. Ancillary activities can distort measures of core operating performance, and peer analyses that rely on comparability of data, unless adjustments are made. An analogy can be drawn to the analytical segregation of non-homogenous activity. Some GAAP rules may require consolidation if a company owns both manufacturing and finance subsidiaries: We would separate the two for analytical purposes.

These adjustments require an appreciation of industry-specific contexts. For example, in the high-technology industry, companies dedicate substantial amounts of capital to research and development efforts and accumulate intellectual property in the form of patents, trade secrets, domain names, etc., which may be sold or licensed to complement revenues generated from core operations.

We consider revenue generated from the licensing of intellectual property to be a part of operating income, and therefore a component of EBITDA, because this arrangement allows for a relatively predictable, recurring source of revenue. However, revenue generated from the sale of intellectual property is not considered part of operating income. While there may be advantages in selling intellectual property, rather than licensing—e.g., the receipt of greater upfront proceeds or the elimination of future responsibilities—this arrangement normally is treated as non-operating income.

In other situations, the sale of assets may be considered recurring. For example, companies that lease or rent automobiles or industrial equipment routinely and periodically dispose of these assets via auctions and/or other sales.

Adjustment procedures

Data requirements

- Amounts of income, expense, and cash flows to be reclassified (including nonrecurring items reported as operating, and recurring items not reported as operating). These amounts are judgmentally determined, based on information disclosed and our assessment.

Calculations

- Add or subtract amounts from respective measures, (e.g., revenue, operating income before and after D&A; D&A; EBIT; EBITDA; operating cash flows and FFO) to reclassify as appropriate. Because operating cash flows and FFO are post-tax measures, they also are adjusted to reflect the tax effects, where feasible.
- Beyond the standard adjustment, additional insights may be gleaned by adjusting individual line items within cost of goods sold or selling, general, and administrative (SG&A) expense, if there is sufficient data to reflect adjustments at such levels. Similarly, ancillary activities data are segregated and separately analyzed, to the extent practicable with available data.

Operating leases

Companies commonly use leasing as a means of financing. The accounting for leases distinguishes between operating and finance leases. Finance leases (also referred to as capital leases) are accounted for in a manner similar to a debt-financed acquisition of an asset, while many operating leases are reflected in the accounts on a pay-as-you go basis. We view the accounting distinction between operating and capital leases as substantially artificial. In both cases, the lessee contracts for the use of an asset, entering into a debt-like obligation to make periodic rental payments.

Our lease adjustments seek to enhance comparability of reported results (both operating and financial) and financial obligations among companies whether they lease assets under leases accounted for as operating or financing leases, or use debt to finance asset acquisition. The operating-lease-adjustment model is intended to bring companies' financial ratios closer to the underlying economics and more comparable, by taking into consideration all financial obligations incurred, whether on or off the balance sheet. The model improves our analysis of how profitably a company employs its leased and owned assets.

Our model does not fully replicate a scenario in which a company acquired an asset and financed it with debt; rather, our adjustment is narrower in scope: It attempts to capture only the debt equivalent of a company's lease contracts in place. For example, when a company leases an asset with a 20-year productive life for five years, the adjustment picks up only the payments relating to the contracted lease period, ignoring the cost of the entire asset that would have been purchased—and depreciated—by a company that chose to buy instead of lease. We have chosen not to use alternative methodologies that capitalize the entire asset because they entail various data and interpretation challenges. In cases where the company has an economic need to use the asset for longer than the lease term, we take account of this qualitatively; however, if the lease is viewed as artificially short, and there is adequate information, such as for sale/leaseback transactions, we capitalize the entire sale amount.

Adjustment procedures

Data requirements

- Minimum lease payments: Noncancelable future lease payment stream (and residual value guarantees if not included in minimum lease payments); discount factor; annual lease-related operating expense for the most recent year; and deferred gains on sale leaseback transactions that resulted in leases accounted for as operating.
- Future-lease payment data are found in the notes to the financial statements. Annual payments for the coming five years (itemized by year) and the aggregate amount for subsequent years are provided under U.S. GAAP. Our model assumes that future payments for years beyond the fifth year approximate the fifth-year amount. Under IFRS, companies are permitted to disclose amounts payable in years two through four in a single combined amount, instead of disclosing separate amounts for each of the next five years. In this case, we assume a flat level of payments in years two through four, based on the total minimum lease payment disclosed for these three years. This approximation—caused by the limited disclosure—does not capture how future payments may decline in these years. Future lease payments are considered net of sublease rental only when the lease and sublease terms match, and the sub-lessee is sufficiently creditworthy.
- The discount factor is determined in one of the following ways: ideally, the imputed discount rate associated with the lease would be used, but rarely is available, and unlikely to be available for all companies in an industry; use the average rate on the company's secured debt; and/or use a rate imputed from the company's total interest expense and average debt.
- Annual operating-lease-related expense is sometimes available in the notes and will be used. When the amount is not separately disclosed (e.g., when presented with contingent rent and other amounts, or incorporated with other costs), it is estimated using the average of the first projected annual payment at the end of the most recent and prior year.

Calculations

- Debt: The present value of the payment stream, determined using the discount factor, is added to debt. (Lease debt is not tax-effected because its taxes will never reflect the analytical construct underlying our adjustment. The company is, in fact, getting the tax treatment afforded to leases—assuming GAAP and tax treatment as operating lease is the same. The actual tax amounts are those included in the accounts—and generally require no adjustment. This contrasts with PRB and ARO adjustments—which may be tax-effected. Those adjustments are based on the anticipation that tax-deductible recognition of the obligations will ultimately be required.)
- Operating income and cash flow measures: The operating-lease-related expense is apportioned to interest and depreciation components, as described below. The effect is to increase operating income measures: SG&A—by the entire amount of the expense; EBIT—by the implicit interest portion; EBITDA—by the implicit interest portion; and FFO—by the implicit depreciation portion. In addition, operating

income would be adjusted to reverse gain or loss on sale/leaseback transactions.

- Interest expense: Interest expense is increased by the product of the discount rate multiplied by the average first-year projected payment for the current and previous years.
- Depreciation: Operating-lease depreciation, i.e., the operating-lease-related expense amount less the calculated lease interest, is added to depreciation expense. (We deliberately calculate EBITDA without adding back the imputed depreciation component, despite the apparent definitional conflict. The cash flow characteristics of leasing do not neatly conform with the alternative of borrowing to acquire—even though our adjustment attempts to equate them. Lease payments represent ongoing cash outflows—quite different than depreciation, or even amortization of asset acquisition-related debt.)
- Capital expenditures: Capital expenditures are increased by an implied amount calculated as the year-over-year change in operating lease debt plus annual operating lease depreciation. This amount cannot be negative. Capital expenditures are also adjusted in the same fashion for capital leases.
- Property plant & equipment: Operating lease debt is added to PP&E to approximate the depreciated asset cost.

Postretirement employee benefits/deferred compensation

Defined-benefit obligations for retirees, including pensions and health care coverage (collectively referred to as PRB), and other forms of deferred compensation are financial obligations that must be paid over time, just as debt must be serviced, so we include them in debt ratios. A company may pre-fund the obligation or part of it (and companies often do pre-fund their pension obligations), which offsets the financial burden. Our objective, therefore, is to reflect the level of underfunding of defined-benefit pension obligations, as well as typically not-funded health care obligations and retiree lump-sum payment schemes, and other forms of deferred compensation. In arriving at adjusted financial measures, we must undo accounting shortcomings that affect balance sheets, cash flow statements, and income statements (under most current GAAP). The adjustments pertain to obligations already incurred, without trying to capture future levels of liability.

When PRB obligations constitute a major rating consideration, we delve more deeply into the company's particular circumstances and its benefits plans. Also, for some companies, funding and liquidity considerations surrounding retiree obligations can be much more important to the credit profile than imputing debt to the financial ratios. This situation typically pertains to speculative-grade companies that tend to have fewer available resources for cash requirements, including meeting mandated funding of PRB obligations.

We do not include in debt any amounts for defined-contribution plans, because they entail no obligations or risks to the sponsor related to past services beyond the current period's payments. We also have a slightly different position regarding multi-employer plans, not otherwise dealt with here. *(See "Standard & Poor's Approach To Analyzing Employers' Participation In U.S. Multi-Employer Pension Plans," published May 30, 2006, on RatingsDirect.)*

A key difference between debt and PRB obligations is the inherent measurement uncertainty, as the benefits and related assets, to the extent they are funded, are variable. Quantifying PRB obligations relies on numerous assumptions, including:

- Employee turnover rates and length of service, according to which benefits vary;
- Mortality rates and dependency status/longevity assumptions, as the employee and his/her dependents' lifespan determine how long the benefit will be paid;
- Future compensation levels, to the extent wages prior to retirement are a factor in determining the amount of the benefit;
- Health care cost inflation, use, and delivery patterns; and
- Discount rate assumptions required to calculate a present value of the future required cash outflows.

Standard financial adjustments cannot easily factor in deviations from normal assumptions on these measurement drivers. However, for some factors, the analysis can, at least, gauge the sensitivity to changes in those assumptions. For example, a rough rule of thumb is that for each percentage point increase or decrease in the discount rate, the liability decreases or increases by at least 10%, and often by 15%-20%. (The more mature the plan, or the higher the market interest rates, the lesser the impact.)

To simplify the numerical analysis, we combine all retiree benefit plan assets and liabilities, for pension, health, and other obligations, netting the positions of a company's plans in surplus against those that are in deficit.

In theory, and over the long term, companies with multiple plans should be able to curtail contributions to over-funded plans and redirect contributions to under-funded plans. In the near term, however, funding surpluses are often hard to tap—and may have adverse tax consequences if drawn—even while cash contribution requirements may be onerous on other, under-funded plans. But, if meeting near-term cash requirements is an important issue for a particular company, its credit profile likely will be driven by liquidity considerations, while debt ratio levels would be of secondary importance.

We focus on the measure of the obligation that reflects a going-concern view. For example, under U.S. GAAP for pensions, this is the projected benefit obligation (PBO), or an equivalent actuarial measure of the ultimate liability. The going-concern view of the company includes the effect of expected wage increases if the benefit attributable to past employment services is tied to employee compensation according to some formula. However, for collectively bargained labor contracts, the PBO does not take account of expected wage increases beyond the term of the existing contract.

We do not use the accumulated benefit obligation (ABO), which takes into account only the benefits payable upon plan termination at period end, or the vested benefit obligation (which is no longer disclosed under U.S. GAAP), because they reflect a shutdown value perspective, rather than an ongoing firm perspective. Similarly, in the U.K., we do not focus on the value of beneficiaries' claims based on a full buyout basis (i.e., based on the price prevailing on the annuity market, where demand is currently insufficiently covered by supply), which often considerably exceeds the amount equivalent to PBO under IFRS or U.K. GAAP. (The ABO and full buyout value are more appropriate measures in our recovery and subordination analyses.)

For other postretirement obligations—including medical liabilities, we use a measure equivalent to the pension PBO. For example, under U.S. GAAP, this is the accumulated postretirement benefit obligation (APBO).

We tax-effect our PRB adjustments—unless the related tax benefits have already been, or are unlikely to be, realized. We use the rates applicable to the company's plans, or, if this is unavailable, the current corporate rate—even while recognizing that fiscal reality may be more complex or dynamic as the company's fortunes change over time. In the typical situation, the company has credible prospects of generating sufficient future taxable income to take advantage of PRB-related deductions and reduce future tax payments. When a company's ability to generate profits is indeed dubious, we would not tax-effect. Moreover, in such cases, the company likely would be so pressured that liquidity—rather than capitalization or coverage levels—would be the overriding analytical focus.

Capital structure

We adjust capitalization for PRB effects by adjusting both debt and equity, where applicable. Debt is grossed up by the company's tax-effected unfunded PRB obligation. Equity is adjusted by the difference between the amount accrued on the corporate balance sheet and the amount of net over/under-funded obligation (net surplus/deficit), net of tax.

Companies following U.S. GAAP recently adopted SFAS 158, and record the unfunded PRB obligation on their balance sheets; companies following IFRS have the option to fully recognize actuarial gains and losses on their balance sheets. Accordingly, our equity adjustment is no longer required in many instances.

Debt is not adjusted down for net surpluses, so net over-funding (surplus) leaves debt unchanged. Equity can be adjusted up (if the net recognized asset is less than the pre-tax surplus) or down. We do not split the debt adjustment between short- and long-term.

While the surplus is not treated as a cash equivalent, it nonetheless can be of value, especially to obviate future contributions. Sometimes it becomes evident that the amount is unrecoverable or cannot be used to offset future contributions. Given inconsistent accounting disclosure regarding the recoverability of surpluses, we rely on inquiries to company management.

Cash flow

We try to identify catch-up contributions made to reduce unfunded obligations, which would artificially depress reported operating cash flows. We view these contributions as akin to debt amortization, which represents a financing, rather than an operating cash flow. Specifically, cash paid (plan contributions plus benefits paid directly to beneficiaries) exceeding the sum of current-period service and net interest costs (that is, interest cost net of actual or expected returns on plan assets) is added back to FFO on a tax-effected basis. We look at actual investment returns for the period and returns normalized for potentially nonrecurring, unusually high or low performance.

Conversely, if the company is funding postretirement obligations at a level substantially below its net expense (service cost and net interest cost), we interpret this as a form of borrowing that artificially bolsters reported cash flow from operations.

In order to appropriately interpret adjusted numbers, note that our cash flow adjustment:

- Reallocates to the period certain costs (service and interest) that often differ from the cash impact in the period;
- Ignores prior service costs and other items such as curtailments, settlements and special termination benefits, and foreign-exchange variations;
- Ignores any income or charge (whether through income-statement or directly recognized into equity) that reflected the recognition of actuarial gains and losses; and
- Until early 2006, was capped at zero (no longer the case).

Income statement

In analyzing profitability (including operating profit and EBITDA), we disaggregate the benefits-cost components that may be lumped into operating income and expenses, allocate the amounts to operating and financial components, and eliminate those components we believe have no economic substance. The period's current service cost—reflecting the present value of future benefits earned by employees for services rendered during the period—is the sole item we keep as part of operating expenses.

The components, if any, that represent accounting artifacts and stem from the smoothing approach of the accounting rules—e.g., amortization of variations from previous expectations regarding plan benefits, investment performance, and actuarial experience—are eliminated from our income measures. As a result of these adjustments, pre-tax and after-tax income no longer match reported amounts.

Interest expense, which results from applying the discount rate to the beginning-of-period obligation to accrete the liability with the passage of time for the reporting period, is essentially a finance charge—and is reclassified as such, if reported differently.

The expected return on plan assets represents management's subjective, long-range expectation about the performance of the investment portfolio; in some accounting systems—such as U.S. GAAP—it may be applied to a smoothed, market-related value, rather than the fair-market values of the assets. We may choose instead to apply a standardized return, to gauge what multiyear average returns can be expected. We note the risks in the asset mix, but only subjectively. (In the future, we may find a way to reflect the risk profile of the portfolios in a more quantitative manner.)

Either way, the return on plan assets is netted against PRB-related interest expense up to the amount of the interest expense reported, but not beyond, as the economic benefits to be derived from such overage are limited. If, however, the actual return is negative, the full amount is treated as an addition to interest expense because the resulting economic detriment to the company is quite tangible.

Adjustment procedures

Data requirements

For the income and cash flow adjustments, amounts for the period of:

- Service cost;
- Interest cost;
- Expected return on plan assets;
- Actual return on plan assets;
- Actuarial gains/losses (amortization or immediate recognition in earnings);
- Prior service costs (amount included in earnings);
- Other amounts included in earnings (e.g., special benefits, settlements/curtailments);
- Total benefit costs; and
- The sum of employer contributions and direct payments made to participants.

For the balance-sheet adjustments:

- PRB-related assets on the balance sheet, including intangible assets, pre-paid or noncurrent assets, or any other assets;
- PRB-related liabilities on the balance sheet, including current and noncurrent liabilities;
- PRB-related deferred tax assets (or tax rate applicable to PRB costs);
- Fair value of plan assets; and
- Total plan obligations.

Note: Relevant pension and other postretirement benefit amounts are combined for all plans.

Calculations

Income-statement adjustments include adjustments to expenses and interest.

- Total PRB costs charged to operating income, less the service cost, yields the PRB adjustment to operating income. This is added to operating income before and after D&A, EBIT, and EBITDA.
- Interest cost less the expected return is PRB interest. In some cases, we may adjust expected returns to normalize it at a more realistic level. If net PRB interest is a cost, we include it in adjusted interest expense (we do not reduce interest expense if expected returns exceed interest cost). This PRB interest is added to reported interest when the net benefit costs are included in operating income. If reported interest already includes an interest component for PRBs (e.g., as may be the case under IFRS), we adjust it, if necessary, to ensure it reflects the amount of PRB interest cost. A similar calculation is made using the actual, rather than expected, return on plan assets.

The adjustment to funds from operations starts with a calculation of excess contributions or PRB borrowing:

- Total employer contributions (including direct payments to retirees), less service costs, less interest costs, plus expected return yields the excess contribution, if positive, or PRB borrowing, if negative. (A similar calculation is made using actual, rather than expected return.)
- The excess contribution or PRB borrowing is reduced by taxes at the rate applicable to PRB costs. That is, the amount is multiplied by (1 - tax rate) to create the PRB adjustment to FFO.
- The excess contribution on PRB borrowing is added or subtracted to or from FFO.

The balance-sheet adjustments affect assets, debt, and equity.

- Plan obligations less assets equals the net pension and postretirement funded status (deficit or surplus).
- The net balance sheet asset (liability) position is determined as the balance sheet assets less liabilities. For the adjustment to debt, if net pension and postretirement funded status is a surplus, debt is not adjusted. If the net pension and postretirement is a deficit, this amount is reduced by the expected tax shield, that is, the amount is multiplied by (1 - tax rate).
- In some jurisdictions, the tax benefit is realized in advance of funding the deficit or paying benefits, for example, when the liability is accrued for tax purposes. The expected tax shield used in our calculation only takes into account amounts that have not yet been received. The adjustment to equity also considers existing balance sheet amounts.
- Equity is adjusted for the tax-effected difference between the deficit/surplus and the net balance sheet assets/liabilities, i.e., multiplied by (1 - tax rate).

Unlike the adjustment to debt, the adjustment to equity can be an increase or decrease.

(Please see "Corporate Ratings Criteria," 2006 edition: Postretirement Obligations; and "Ratings Implications Of New FASB Standard On Pensions And Other Postretirement Benefit Obligations," published Sept. 29, 2006, on RatingsDirect.)

Power purchase agreements

We view purchased power supply agreements (PPAs) as creating fixed, debt-like, financial obligations that represent substitutes for debt-financed capital investments in generation capacity. In a sense, a utility that has entered into a PPA has contracted with a supplier to make the financial investment on its behalf. Consequently, by adjusting financial metrics to incorporate PPA fixed obligations, we achieve greater comparability of utilities that finance and build generation capacity and those that purchase capacity to satisfy customer needs.

PPAs do benefit utilities by shifting various risks to the suppliers, such as construction risk and most of the operating risk. The principal risk borne by a utility that relies on PPAs is the recovery of the costs of the financial obligation in rates. Differentiating the risk profiles of utilities that take divergent approaches is incorporated in our qualitative business-risk assessments.

We calculate the present value (PV) of the future stream of capacity payments under the contracts as reported in the financial statement footnotes, or as supplied directly by the company. The discount rate used is equivalent to the company's average cost of non-securitization debt. For U.S. companies, notes to the financial statements enumerate capacity payments for the coming five years, and a thereafter period. We often have access to company forecasts that show the detail underlying the thereafter amount; otherwise, we divide the amount reported as thereafter by the average of the capacity payments in the preceding five years to derive an approximation of annual payments after year five.

In calculating the amount we add to debt, we also consider new contracts that will commence during the forecast period. Such contracts are not reflected in the notes to the financial statements—but information regarding these contracts may be provided to us by the company.

If these contracts represent extensions of existing PPAs, they are immediately included in the PV calculation. However, a contract sometimes is executed in anticipation of incremental future needs, so the energy will not flow until some later period and there are no interim payments. In these instances, we incorporate that contract in our projections, starting in the year that energy deliveries begin under the contract, just as if the company had purchased a plant at that juncture. That way, the debt imputation is viewed in the context of all the related activity, including revenues and cash flow from the forecast demand. (Of course, the projected PPA debt is included in projected ratios. That way, the future PPA figures as a current rating factor, even if it is not included in the current-year ratio calculations.)

The calculated PV is adjusted to reflect the benefits of regulatory or legislative cost recovery mechanisms. The adjustment reduces the debt-equivalent amount by multiplying the PV by a specific risk factor that pertains to each contract. The stronger the recovery mechanisms, the smaller the risk factor. These risk factors typically range between 0% and 50%, but can be as high as 100%.

A 100% risk factor would signify that substantially all risk related to contractual obligations rests on the company, with no mitigating regulatory or legislative support. For example, an unregulated energy company that has entered into a tolling arrangement with a third-party supplier would be assigned a 100% risk factor. Conversely, a 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers. This fact pattern frequently is found among regulated utilities that act as conduits for the delivery of a third party's electricity, and essentially deliver power, collect charges, and remit revenues to the suppliers. These utilities typically have been directed to divest their generation assets; are barred from developing new generation assets; and the power supplied to their customers is sourced through a state auction or third parties that act as intermediaries between retail customers and electricity suppliers.

Intermediate degrees of recovery risk are presented by a number of regulatory and legislative mechanisms. For example, we employ a 50% risk factor in cases where regulators use a utility's rate case to establish base rates to provide for the recovery of the fixed costs created by a PPA. While we view this type of mechanism as generally supportive of credit quality, the utility still needs to obtain approval to recover costs and the prudence of PPA capacity payments in successive rate cases to ensure ongoing recovery of its fixed costs. If a regulator has established a power cost adjustment mechanism that recovers all prudent PPA costs, a risk factor of 25% is employed, because the recovery hurdle is lower than it is for a utility that must litigate time and again its right to recovery costs.

In certain jurisdictions, true-up mechanisms are more favorable and frequent than the review of base rates, but still do not amount to pure fuel adjustment clauses. Such mechanisms may be triggered by financial thresholds or passage of prescribed periods of time. In these instances, a risk factor between 25% and 50% is employed.

Legislatively created cost-recovery mechanisms are long-lasting and more resilient to change. Consequently, such mechanisms lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors.

We do not impute debt for supply arrangements if a utility acts merely as a conduit for the delivery of power. As an example, New Jersey's vertically integrated utility companies were transformed into pure transmission and distribution utilities. The state commission, or an appointed proxy, leads an annual auction in which suppliers bid to serve the state's retail customers, and the utilities are protected from supplier default. The state's utilities merely deliver power and collect revenues from retail customers on behalf of the suppliers. Therefore, we impute debt only to New Jersey utilities' qualifying facility and exempt wholesale generator contracts—and not for other electricity supply contracts where the utilities merely act as conduits between the winners of the regulator's supply auction and the end-user, retail customers.

We also exclude PPAs with durations of less than one year where they serve merely as gap fillers, pending either the construction of new capacity or the execution of long-term PPA contracts. These contracts are temporary—and we focus on the more permanent situation, which is factored into the forecast ratios.

Given the long-term mandate of electric utilities to meet their customers' demand for electricity, and also to enable comparison of companies with different contract lengths, we use an evergreening methodology. Evergreen treatment extends the duration of short-and intermediate-term contracts to a common length of around 12 years. To quantify the cost of the extended capacity, we use empirical data regarding the cost of developing new peaking capacity, incorporating regional differences. The cost of new capacity is translated into a dollars-per-kilowatt-year figure using a proxy weighted average cost of capital and a proxy capital recovery period.

Some PPAs are treated as operating leases for accounting purposes—based on the tenor of the PPA or the residual value of the asset upon the PPA's expiration. We accord PPA treatment to those obligations, in lieu of lease treatment, if companies identify them to us. That way, such PPAs will not be subject to a 100% risk factor for analytical purposes as though they were ordinary leases; rather, the PV of the stream of capacity payments associated with these PPAs is reduced to reflect the applicable risk factor. (PPAs treated as capital leases for accounting purposes do not fall under our PPA adjustment.)

Long-term transmission contracts can also serve in lieu of building generation, and, accordingly, fall under our PPA methodology. In some cases, these transmission contracts provide access to specific power plants, while other transmission arrangements provide access to competitive wholesale electricity markets. We view these types of transmission arrangements as extensions of the power plants to which they are connected or the markets that they serve. Accordingly, we impute debt for the fixed costs associated with such transmission contracts.

Adjustment procedures

Data requirements

- Future capacity payments obtained from the financial statement footnotes or from management.
- Discount rate: the company's cost of nonsecuritized debt.
- Analytically determined risk factor.

Calculations

- Balance-sheet debt is increased by the PV of the stream of capacity payments multiplied by the risk factor.
- Equity is not adjusted, because the recharacterization of the PPA implies the creation of an asset, which offsets the debt.
- PP&E and total assets are increased for the implied creation of an asset equivalent to the debt.
- An implied interest expense for the imputed debt is calculated by multiplying the utility's average cost of nonsecuritized debt by the amount of imputed debt (or, average PPA imputed debt, if there is fluctuation of the level), and is added to interest expense.
- The cost amount attributed to depreciation is reclassified as capex, thereby increasing operating cash flow and FFO.
- We impute a depreciation component to PPAs. The depreciation component is derived by multiplying the relevant year's capacity payment by the risk factor and then subtracting the implied PPA-related interest for that year. Accordingly, the impact of PPAs on cash flow measures is tempered.
- Some PPA contracts refer only to a single, all-in energy price. We identify an implied capacity price within such an all-in energy price, to calculate an implied capacity payment associated with the PPA. This implied capacity payment is expressed in dollars per kilowatt-year, multiplied by the number of kilowatts under contract. (In cases that exhibit markedly different capacity factors, such as wind power, the relation of capacity payment to the all-in charge is adjusted accordingly.)
- Operating income before D&A and EBITDA are increased for the imputed interest expense and imputed depreciation component, the total of which equals the entire amount paid for PPA (subject to the risk factor).
- Operating income after D&A and EBIT are increased for interest expense.

(Please see "Standard & Poor's Methodology For Imputing Debt for U.S. Utilities' Power Purchase Agreements," Published May 7, 2007, and "Credit FAQ: Imputed Debt Calculation For U.S. Utilities' Power Purchase Agreements," published March 30, 2007, on RatingsDirect.)

Share-based compensation expense

We view the value of equity instruments *(for example, stock options and restricted shares awards)* granted to employees and/or other service providers as an outlay that should be taken into account in evaluating issuers' performance and profitability. When we assess a company's ability to generate a real, all-in return on capital employed, we should not view differently companies granting equity from peers using cash as a form of compensation. Although often not representing a direct or an immediate call on a company's cash resources, these grants are made in exchange for, or in anticipation of, services to be provided: They have a real economic value and so should be considered.

In analyzing the financial aspects of equity awards granted by an issuer, we consider adjustments to:

- Normalize the value of these grants in calculating earnings and performance-based metrics. That is, certain accounting regimes mandate expensing of stock-based grants while others do not. In addition, certain practices employed by management, such as vesting acceleration and other award modifications, could meaningfully affect reported results. Accordingly, certain adjustments may be warranted for more meaningful peer and period-over-period comparisons.
- Highlight the effect that these arrangements might have over time on cash flows. That is, although most awards do not result in cash being exchanged upon grant, future cash flows are clearly affected. This occurs as a result of payments received by the company upon exercise or issuance of shares; payments made by the company for share repurchases (to mitigate EPS dilution); a company's practice to settle the value of equity grants in cash in lieu of

shares; and tax savings generated by the favorable tax treatment generally afforded to options and other grants.

- Separately, we try to ascertain the effectiveness of a company's grants in aligning employee incentives with shareholders' and creditors' objectives.

Until recently, the major accounting regimes (e.g., IFRS, U.S. GAAP, Canadian GAAP, and Australian GAAP) did not mandate expensing of these costs. Now most require the fair value of equity-based grants (or an approximation of that value) to be included as an expense in the income statement. This amount is generally expensed over the benefiting period, i.e., the period the employee is assumed to provide services in exchange for the award. Often the vesting period is used as a proxy. Prior to the advent of IFRS and the recent mandating of expensing under U.S. GAAP for all stock-based grants, the accounting was greatly fragmented and inconsistent among companies and jurisdictions, and also varied according to the form of the award. For example, although restricted shares or stock appreciation rights may be economically equivalent to stock option grants, the accounting differed. Further, disclosures of stock-based compensation arrangements, which were lacking in the past, have vastly improved as a result of governance and transparency requirements by accounting-standard setters, securities regulators, and exchanges, providing more pertinent data on these arrangements.

Profitability analysis

Our objective is to capture compensation cost in our profitability measures—regardless of the means of payment (i.e., whether paid in cash, shares, options or other in-kind payment)—as fully and as consistently as possible.

With the recent accounting changes, most rated companies now expense the cost of equity-based grants, so the consistency of reported earnings is significantly enhanced, obviating in many cases the need to define a different common basis for analysis. However, where information enabling quantification is not available, we employ a qualitative assessment, to be conscious of the difference among peers.

Companies may, at times, modify their share-based awards, grant a one-time award (e.g., upon an acquisition), or accelerate vesting (e.g., upon a change in control or downsizing). These actions could meaningfully alter reported income and introduce discrete volatility to earnings. However, adjustments for these variants generally are not feasible as a practical matter, and are attempted only where material and the relevant information is available.

Cash-flow analysis

When a company grants share-based awards, generally no cash is paid or received. Cash-flow consequences, if any, only arise when the options are exercised (e.g., as a result of payment of the exercise price and from associated tax benefits). For some other grants, such as stock appreciation rights (SARs) payable in shares and restricted share grants, no cash changes hands at all. Just as with all issuance of equity, the company's financial position is enhanced, or at least is not diminished, as a result of the grant (assuming settlement is effected with shares, and the grant/exercise is not tied to commensurate repurchases). From a cash-flow standpoint, companies would gain flexibility to the extent that stock-based grants provide an alternative to cash compensation and their creditors should be better off, while their shareholders will be diluted.

Our cash-flow measures, such as FFO and OCF, are not affected by share-based grants. Being a non-cash item, share-based related expense will continue to be backed out on the cash flow statement. Because options and restricted share grants represent non-cash events, our key cash flow ratios—FFO to total debt, EBITDA to interest, and debt to EBITDA—exclude stock option expense. Accordingly, for companies whose stock-based compensation expense (payable in shares) has been deducted, we adjust EBITDA measures by adding back the expense.

Unlike options or restricted share awards, certain other share-based arrangements are payable solely in cash (e.g., stock appreciation rights required to be settled in cash), and represent a future call on a company's cash flow. The obligations under these arrangements are treated as debt.

For tax-reporting purposes, the exercise or the point of vesting (not granting) of certain stock-based awards often generates a tax-deductible expense, regardless of whether the company has been expensing stock-option grants for financial reporting purposes. Tax credits are shown as an operating item on the cash flow statement under U.S. GAAP only to the extent they relate to the accounting expense; if the tax deduction exceeds the amount attributable to the accounting expense, such excess is a financing item. Analytically, we view tax benefits more appropriately as a financing item on the cash flow statement, since they are triggered only upon equity issuance.

To mitigate dilution caused by options and other share-related grants, companies often engage in share repurchases. Arguably, if a company regularly reverses the dilution resulting from the exercise of share-based awards through share repurchases, the related cash outlays (net of cash proceeds from the exercise) could be treated as a cash operating expense. However, we view a company's decision to repurchase its shares as a separate matter—and part of the company's overall corporate finance strategy. Accordingly, we determine the level of expected share repurchases in the context of a broader assessment of liquidity, capitalization, and financial policy.

In contrast, when an issuer enters into derivative or similar contracts to repurchase shares at a future date, we view these contracts as precursors to such purchases—and incorporate the repurchase immediately in the analysis. Still, even in the absence of such contractual arrangements, the analysis incorporates the eventual share repurchases if they are anticipated. We adjust debt by adding amounts that are anticipated as necessary to fund these transactions.

Additional considerations

For U.S. tax purposes, generally the exercise (not granting) of certain stock options results in a tax-deductible expense to the employer. However, for GAAP purposes, the company expenses the fair value of stock options, which is determined at the grant date, ratably over the related service period. As a result of the use of the grant date fair value to determine the accounting expense, rather than an exercise-date intrinsic or other value for tax deduction purposes, the book and the tax expenses will differ. Furthermore, U.S. GAAP does not allow companies to record a reduction to income tax expense on their income statements for these excess tax benefits. Instead, the tax benefit is recorded directly as an incremental increase to equity (more specifically, additional paid-in capital) and a reduction of taxes payable (i.e., never recorded in as a benefit in the income statement). Consistent with our view that the tax benefits are more financing in nature, because they relate to equity issuance, this will not give rise to an adjustment.

If the options ultimately expire unexercised, any previously recorded accounting expense (recorded based on the award's initial fair value) is not reversed under U.S. GAAP. Although in this circumstance no tax deduction would be generated at all, it would result in a deferred tax asset being recorded on the company's balance sheet over the expense recognition period (because the book expense and resulting deferred tax assets are calculated based on the initial fair value). This tax asset is reversed through earnings only upon expiration of the exercise period. This requirement can cause large deferred tax assets, unlikely to be realized, to remain on a company's balance sheet, causing artificially inflated equity balance in circumstances in which a company's fortunes are adversely changing, and its options are moving substantially out of the money (rendering both exercise and use of the tax benefit improbable). Analytically, it would be more appropriate to reverse the asset amount against equity when it becomes apparent that use of the benefits is unlikely. Adjustments for these situations are considered only in rare circumstances.

Both IFRS and U.S. GAAP now require the expensing of stock options and other share-based employee compensation. However, to facilitate the transition from the prior approach of not expensing, the transition provision allows companies to apply this approach only to grants that were made after a specific date (e.g., Nov. 7, 2002, under IFRS). As a result, costs for an increasing proportion of outstanding grants will be expensed over time. We have generally not attempted to adjust earnings measures to include the missing expenses in the early years of the transition.

Adjustment procedures

Data requirements

- Total period share-based compensation expense reflected in the financial statements. (Amounts may be available in the statements or in the notes.)
- In jurisdictions that do not require expensing of such compensation, an estimate of what would be expensed.
- Amount of deferred taxes unlikely to be realized.
- Tax cash flows included in operating that we view as financing.
- Estimate of amounts to be used for share repurchases.

Calculations

- EBITDA: Where noncash stock compensation costs have been expensed, we reverse the expense amount.
- SG&A, Operating income before and after D&A, and EBIT: In jurisdictions where share-based compensation is not required to be expensed, the estimated amount is deducted from these profitability measures.
- Tax assets that are unlikely to be realized are subtracted from assets and equity.
- Taxes that are financing in nature are added to operating cash flow and FFO.
- Debt is increased—and equity decreased—for related share repurchases that are contractually committed or otherwise imminent.

(Please see "Analytic Implications Of Stock-Based Compensation Accounting," published March 24, 2005, and "Camouflaged Share Repurchases: The Rating Implications of Total-Return Swaps and Similar Equity Derivatives," published Dec. 7, 2000, on RatingsDirect.)

Stranded costs securitizations of regulated utilities

For rate-regulated utilities, we remove the effects of debt related to securitization of stranded costs, to the extent that debt is serviced separately by the utilities' customers through direct inclusion in rates. Because the customers, not the utility, are responsible, by statute, for principal and interest payments, we remove the debt from the balance sheet for analytical purposes. We also remove related amounts from revenue, depreciation, and interest.

Adjustment procedures

Data requirements

- Amount of securitized debt related to stranded costs on the utility's balance sheet at period end;
- Interest expense related to securitized stranded-cost debt for the period; and
- Principal repayments on stranded-cost securitized debt during the period.
- Note: We obtain the data from the financial statements and footnotes of the utility; or separate special purpose vehicle (SPV) created for the debt securitization; or information received directly from the utility.

Calculations

- Adjustment to debt: We subtract the stranded-cost securitized debt from total debt.
- Adjustment to revenues: We remove the revenue earned from customers that is committed to paying securitized debt principal and interest from total revenues. We assume that revenue equals the sum of interest and principal payments made during the year.
- Adjustment to operating income before depreciation and amortization and EBITDA: We remove the revenue earned from customers committed to paying principal and interest on securitized debt.
- Adjustment to operating income after depreciation and amortization and EBIT: We remove the revenue earned from customers committed to paying principal and interest. We also remove depreciation and amortization related to the regulatory asset, which we assume equals the sum on principal payments during the period. As a result, the reduction to operating income after D&A is only for the interest portion.
- Adjustment to interest expense: We reduce interest expense by interest expense of the securitized debt.

- Operating cash flows: We reduce operating cash flows for revenues and increase for the assumed interest amount related to the securitized debt. This results in a net decrease to operating cash flows equal to the principal repayment amount.

(Please see "Securitizing Stranded Costs," published Jan. 18, 2001, on RatingsDirect.)

Surplus cash

The credit profile of companies that have accumulated cash is, of course, enhanced by the available liquidity. But our analytical methodology regularly goes a step further, by adjusting both financial and operating ratios to reflect a company's surplus cash (that is, unless the surplus is deemed to be only temporary).

Industrial credit ratios are intended to capture the degree to which a company has leveraged its risk assets, and highly liquid financial assets often involve virtually no risk. Moreover, ratios are designed to indicate a company's ability to service and repay debt obligations from operating cash flow, and surplus cash and/or highly-liquid assets are, in a sense, available to repay debt apart from ongoing cash flow generation. Accordingly, we often net surplus cash against debt and debt-like obligations—so that net debt is what figures in ratio calculations.

In some situations—only where the surplus cash is structurally linked to debt that would not be needed, were it not for the cash holdings—we also use a net interest expense when calculating the denominator of coverage ratios, such as FFO/interest, EBIT/interest and EBITDA/interest. (Absent such linkage, we use gross interest in the denominator. Also, since interest income is differentiated from operating income, it is generally not included in the numerator.)

Further, maintenance of surplus cash distorts operational benchmarks and return on assets (ROA) measures that are important for peer comparisons in some sectors, such as pharmaceuticals. Given the relatively low returns on low-risk financial assets, maintaining such assets depresses asset-related margins (even without taking into account interest expense required if the company is financing the cash with debt that otherwise would not be needed).

The key analytical considerations regarding net debt adjustments are the quality of the financial assets themselves, and the company's purpose and strategies for maintaining them—although doing so involves commensurately higher levels of debt. Some of the possible strategies—and what they imply for the permanence of the surplus—are discussed below.

Virtually all companies require some cash to facilitate their operations. Retailers, restaurants, and supermarkets, for example, need cash to make change. More broadly, companies require a certain level of cash for very-near-term liquidity. We do not give any special credit or make any adjustments for cash that is merely adequate to support ongoing operations, even though the amount can sometimes be quite substantial—especially for companies that operate numerous facilities, and those that transact in diverse currencies.

Companies engage in dialogue with us to help us gauge these near-term operating liquidity needs, and our sector comparisons and reviews also target peer consistency regarding maintenance of sufficient liquidity. Apart from potential netting for surpluses, maintaining adequate liquidity is always an important rating consideration. A company with a deficient level of cash for working capital needs would be penalized in its rating assignment.

However, many companies possess still greater cash, and/or liquid, low-risk, financial resources. Several different possible purposes and strategies could apply. This is important to our analytical treatment: There are many situations in which we use net calculations and, many others where we do not, usually determined by the company's strategies. The strategies explained below are in descending order, starting with the most supportive of a net approach and concluding with a number of strategies that do not lead to a net approach.

Strategies that support net-debt treatment

- Defeasance (both legal and economic). Because the company places very high-quality assets in a trust to cover the interest and principal of a specific debt issue, this is the most obvious application of the net debt adjustment. *(See "Defeasance Of*

Corporate Bonds May Be Gaining Popularity," published July 25, 2006, on RatingsDirect).

- Tax arbitrage. Some companies manufacture in various tax havens; retain related profits in those low-tax locales and avoid tollgate taxes by holding financial investments there; while financing and incurring tax-deductible interest expense in higher-tax rate jurisdictions. Such structural basis for maintaining cash is another solid reason for applying the net debt adjustments. (However, for analytical purposes, any "tollgate" taxes payable upon repatriation are subtracted from the cash.) The large, cash-rich U.S. pharmaceutical companies offer a good example of this tax arbitrage strategy. And, given the magnitude of this aspect of these companies' finances, profitability measures could be quite distorted without also adjusting return on asset ratios to a net basis. *(See "Credit FAQ: Tax Relief On Foreign Cash And Its Special Benefit To U.S. Drug And Medical Device Firms," published Sept. 14, 2004, and "Ratings Implications Of Earnings Repatriations Under The American Jobs Creation Act," published June 26, 2006, on RatingsDirect.)*
- Funding future payment of obligations—especially retiree obligations. Some companies may earmark financial assets on their balance sheet to provide for their retiree benefit obligations. In particular, some large German corporations assert that this is their financial policy. Indeed, while these assets are not legally segregated, we would view them as offsetting the liability. Application of the net debt approach in such cases presumes that the liability itself is sufficiently debt-like to be included in our definition of adjusted debt. (U.S., U.K., and Dutch companies, among others, are forced by law to fund their pension obligations in a trust. Our pension adjustment adds back only any unfunded portion, which is equivalent to netting these financial assets against the debt-like pension liability.)
- Meet seasonal requirements. A company may choose to pre-fund its intrayear borrowing needs, by borrowing (or not repaying outstanding debt balances), holding the proceeds in cash or near-cash investments, drawing down the cash as the year progresses, and then replenishing it at period end. The company should not be penalized relative to a company that instead relies on borrowing only as the need actually materializes, thus avoiding the debt showing up on its yearend financial statements. (In both cases, there may be equal prudence, since the latter company would typically be able to rely on a revolving credit agreement.) To avoid such a distortion and promote comparability, we would use a net-debt approach. However, it would be tricky to estimate the impact on interest expense involved for this pattern, which is one reason we are reluctant to focus on net interest expense.
- Maintain access to financial markets. Very similar to the above strategy, some companies believe it is in their best interests to keep a fairly stable presence in the financial markets, especially in commercial paper markets. They maintain market presence on a regular basis, and avoid going in and out of the markets as their cash flow patterns would dictate.

Strategies that do not support net-debt treatment

- Cyclical safety net. Some companies tend to accumulate cash during good times, and hold onto it for self-preservation during expected lean years. For companies that have large ongoing capital requirements, this can be critical. The large U.S. auto companies offer a dramatic example. Similarly, high-technology companies tend to operate with a large cash cushion, given the vicissitudes of the technology product life cycles. Such cash is not really an offset to debt, and net debt is not used as the basis for analysis in these instances. (Nonetheless, it is hard to forecast how much cash is appropriately dedicated to spending in future downturns. So the analyst might calculate supplementary ratios based on netting, just to gain perspective and for peer comparison purposes.)
- Reserve for investment opportunities. Cash earmarked for investment in operations—

expansion or capital projects—or acquisitions does not qualify for netting against debt. The cash position is temporary, although some companies may take their time until the opportunity they seek arrives. Of course, having such cash to invest is a great positive that must not be overlooked; it figures in other aspects of the analysis: The potential additional cash flow that can be anticipated from enlarged operations is considered in financial projections, and the current availability of cash enhances liquidity.

- Awaiting return to shareholders. In the current financial environment, this situation may be the most common, at least in the U.S. Many companies that have been successful at generating surplus cash are motivated to repurchase stock or pay out special dividends. While shareholder enrichment programs may stretch out over several quarters or even a few years, the cash position of such companies is ephemeral, and should not be netted against debt.

There are many instances where the purpose may be mixed or the strategy unclear. Local business practice can then form the basis for deciding whether the cash position is likely to be long-lasting. Accordingly, companies with surplus cash that operate in the European context are regularly afforded net debt treatment, given the acceptance—even tradition—of companies operating permanently with surplus cash. (Whatever portion is deemed to be needed for operations is excluded from the adjustment.)

In contrast, North American companies operate in an environment that looks askance at cash accumulation. Shareholders expect these funds to be invested, or returned to them for reinvestment. We therefore presume that, in most cases, surplus cash will be distributed to shareholders sooner or later. Accordingly, few companies in North America are analyzed on a net-debt basis.

Some companies participate in global industries, and may be influenced, to some extent, by the behavior of cross-border peers. This could provide additional insight into what to expect in those instances.

A company's excess cash may be invested in assets of varying quality or liquidity. We tend to be fairly conservative about which assets can be used to fully offset debt. However, a diversified portfolio of assets—such as traded equities, for example—can constitute a reasonably high quality investment, and is certainly very liquid. We have sometimes taken a net approach even with respect to nonfinancial assets, when they exhibit similar critical aspects of low risk and liquidity. For example, agricultural commodity and energy trading companies hold inventory against committed orders. Netting the value of these commodities against debt allows a better picture of the true credit risks.

To the extent that asset values may be subject to decline, we would haircut the investment prior to the netting adjustment. There are situations where we would not adjust for excess cash on the balance sheet because the company has only limited access to the funds. Such exceptions include:

- Funds held at partially owned subsidiaries. Joint-venture partners or minority shareholders may insist on maintaining significant liquidity at the subsidiary level, or may otherwise limit the repatriation of cash to the group's central treasury operations. Restrictive bank loan covenants at these units create similar restrictions.
- Operating subsidiaries that are regulated. These business units may be prevented from up-streaming cash to their parents, or may have to maintain substantial cash balances for regulatory reasons.
- Captive insurance subsidiaries. While cash appears unencumbered, it usually has to be invested in line with the subsidiary's insurance status and regulations.
- Pension funding vehicles. Even pension surpluses are generally regarded as inaccessible for all practical purposes.

Adjustment procedures

Data requirements

- The amount of surplus cash is judgmentally determined, based on our assessment of liquidity available to repay debt.
- Estimated taxes that would be subject to collection upon repatriation, if applicable.

Calculations

- Debt and cash and investments are reduced by the surplus cash amount, net of related taxes. However, the resulting debt amount may never be negative.

- If the cash and debt are structurally linked, interest expense is reduced by an amount that corresponds to earnings on the surplus cash.

(Please see "Net Debt Adjustments Reflect Asset Quality, Strategic Intent," published Feb. 22, 2007, on RatingsDirect.)

Trade receivables securitizations

Securitization is an important financing vehicle for many companies, often providing lower—cost, more diverse sources of funding and liquidity than otherwise available to the company. However, securitizations do not ordinarily transform the risks or the underlying economic reality of the business activity, and do not necessarily provide equity relief (i.e., that having accomplished a securitization, the issuer can retain less equity, or incur more debt, than otherwise would be the case, without any change in its credit quality).

To the extent the securitization accomplishes true risk transfer (i.e., all risks—contractual, legal, and reputational), the transaction is interpreted as an asset sale. Yet, in the much more common case, the company retains the bulk of risks related to the assets transferred, and the transaction is akin, in our view, to a secured financing. More importantly, perhaps, we do not give any benefit for securitization of assets that will be re-generated in the ordinary course of business (and financed on an ongoing basis).

Key considerations in assessing the extent of equity relief include:

- Riskiness of the securitized assets. The only risk that can be transferred is that which existed in the first place. If, as is often the case, an issuer securitizes its highest-quality or most liquid assets, that limits the extent of any meaningful equity relief.
- First-loss exposure. The issuer commonly retains the first-loss exposure, to enhance the credit protection afforded for the securitized debt. For the securitized debt to be highly rated, the extent of enhancement must be a multiple of the expected losses associated with the assets. The first-loss layer thus encompasses the preponderance of risk associated with the securitized assets, and the issuer's total realizations from the securitization will vary depending on the performance of the assets. Often, only the risk of catastrophic loss is transferred to third-party investors—risk generally of little relevance in the corporate rating analysis.
- Moral recourse. How the company would behave if losses did reach catastrophic levels. Empirical evidence suggests companies often believe they must bail out troubled financings (for example, by repurchasing problematic assets or replacing them with other assets) to preserve access to this funding source and, more broadly, to preserve their good name in the capital markets, even though they have no legal requirement to do so. Moral recourse is magnified when securitizations are a significant part of a company's financing activity, or when a company remains linked to the securitized assets by continuing in the role of servicer or operator.
- Ongoing funding needs. Even if it were contractually and legally certain that the risks related to a given pool of assets had been fully transferred and the issuer would not support failing securitizations, equity relief (or an analytical deconsolidation) still would not necessarily have been achieved. If, for whatever reason, losses related to the securitized assets rose dramatically higher than initially anticipated, and if the issuer has a recurring need to finance similar assets, future access to the securitization market would be dubious—at least economically. Future funding needs would then have to be met by other means, with the requisite equity (and the equivalent level of borrowings) to support them. Thus, even if a company separately sells the first-loss exposures, or sells the entire asset without retaining any first-loss exposure, it would not achieve equity relief.

The accounting treatment of securitizations may not be congruent with our analytical perspective, and, accordingly, adjustments to the reported financials often are necessary (especially for companies reporting under U.S. GAAP, since many securitizations remain on-balance sheet under IFRS).

For transactions in which a company retains the preponderance of risks (including those related to ongoing funding needs), we calculate ratios where the outstanding amount of securitized assets are consolidated, along with the related securitized debt—regardless of the accounting treatment. If securitization is used essentially to transfer risk in full and there are no contingent or indirect liabilities, we view the transaction as the equivalent of an asset sale. When necessary, then, we recast the assets, debt, earnings and cashflows, and shareholders' equity accordingly, including adjusting for deferred tax effects and imputed interest.

Issues/limitations of adjustments

When securitizations are accounted for as sales, they commonly give rise to upfront gain/loss-on-sale effects, which represent the present value of the estimated difference between the asset yield and the securitization funding rate and other securitization-related costs. For securitizations that we are putting back on the balance sheet, it is appropriate to back out such gains and spread them out over the life of the securitizations, given the uncertainty about whether the earnings will ultimately be realized as expected and their essentially non-recurring character. Losses that reflect the discount on sale are also backed out, to avoid double-counting the interest component of the transactions.

To impute interest, we generally have to approximate a rate, given the lack of precise information that is available. Since securitizations tend to be relatively well-secured and risk-free for the investor, we assume a rate that approximates the risk-free rate, currently 5%.

In theory, it might be desirable to fully recast the income statement, and consolidate off-balance-sheet securitizations, but as a practical matter, this is difficult to accomplish. Still, some companies have voluntarily included pro forma schedules in their public disclosures to enable such analysis.

Cash inflows or outflows related to working capital assets or liabilities, or finance receivables, are classified as operating in nature on the statement of cash flows under U.S. GAAP and IFRS. Hence, securitizations affect operating cash flow, with particularly significant effects possible in reporting periods when securitizations are initiated or mature. The reporting convention varies in line with the balance sheet classification. If the securitization is consolidated, the related borrowings are treated as a financing activity. If the securitization is not consolidated, it is as if the assets self-liquidated on an accelerated basis: No debt incurrence is identified separately, either as an operating or financing source of cash. When our analytic view is that securitizations should be consolidated (or, in rare situations, when those that are consolidated should not be), it would be desirable to recast the statement of cash flow accordingly—to smooth out the variations in operating cash flow that can result from the sale treatment of the securitization, which can give a distorted picture of recurring cash flow. Again, as a practical matter, this often can be difficult to accomplish.

Adjustment procedures

Data requirements

- Identify the period-end amount and average outstanding amount of trade receivables sold or securitized, for which an adjustment is warranted, that are not on the balance sheet.

Calculations

- Debt and receivables are increased by the amount of trade receivables sold or securitized.
- Interest expense is increased by an amount of interest imputed at the risk-free discount rate.
- Operating cash flows are adjusted to remove the proceeds from the securitization when there is an increased level of securitization—upon initiation of securitization or subsequent fluctuation in amounts securitized. Merely rolling over existing securitization requires no cash flow adjustment.

(Please see "Securitization's Effect On Corporate Credit Quality," published Nov. 28, 2005, and "Finance Company Rating Methodology: Credit Ratios To Be Analyzed On A Managed Basis," published Feb. 23, 2001, on RatingsDirect.)

Volumetric production payments

A volumetric production payment (VPP) is an arrangement in which an exploration and production (E&P) company agrees to deliver a specified quantity of hydrocarbons from specific properties to a counterparty (often a financial institution) in return for a fixed amount of cash received at the beginning of the transaction. The seller often bears all of the production and development costs associated with delivering the agreed-upon volumes. The buyer receives a nonoperating interest in oil and gas properties that produce the required volumes. The security is a real interest in the producing properties that is expected to survive bankruptcy of the E&P company that sold the VPP. When the total requisite units of production are delivered, the production payment arrangement terminates and the conveyed interest reverts back to the seller.

We view production payments structured with a high level of security to production coverage as debt-like obligations, and adjust financial and operating analysis accordingly. The retention of risk in VPPs is central to our treatment of such deals as largely debt-like.

The accounting for VPPs affects the seller's financial statements and also operating statistics in several ways. The VPP volumes (i.e., the amount of oil and gas required to be delivered under the agreement) are removed from the seller's reserves. Proceeds received for the VPP increase the seller's cash balances, and the seller books a deferred revenue liability—or debt—to reflect the obligation under the agreement. Revenues and costs incurred to produce the VPP volumes are included in the seller's income statement as and when the oil and gas is produced. Operating statistics calculated on a per-barrel basis will be overstated because they include both the amortization of deferred revenues and costs, but do not factor in the volumes related to the VPP. In the case of lifting costs, for example, barrels produced in the numerator are lower, while the expense in the denominator continues to include the cost of producing the VPP volumes.

When the necessary data are available, we adjust the reported results to minimize the distortion caused by accounting for a production payment. The required volumes are returned to reserves and deferred revenue is treated as debt. Similarly, the oil and gas volumes produced to meet the VPP requirements are added to the E&P company's production when calculating per-barrel sales and lifting costs. This treatment reflects the view that VPPs are conceptually similar to secured debt, rather than asset sales. The similarity pertains in typical deals, in which the reserves included in the production agreement are significantly greater than the required volumes. The seller bears the obligation to deliver the agreed-upon volumes, and retains the production and a significant amount of reserve risk, while receiving the benefit of fixing commodity prices. A VPP structured with minimal coverage would be viewed as closer to an asset sale, since the transfer of risk would be more substantial.

Adjustment procedures

Data requirements

- Amount of VPP-related deferred revenue reported on the balance sheet at period end;
- Oil and gas reserve data (related to VPPs that have been removed from reported amounts);
- Remaining quantity of oil and gas reserves removed from reported reserves at end of period (yet to be delivered); and
- Oil and gas volumes produced during the year from the VPPs.

The amount of deferred revenue related to VPPs at period end is obtained from the financial statements. Reserve quantities may come from the financial statements or from the company.

Calculations

- Adjustment to debt: We add the amount of deferred VPP revenue at period end to debt.
- Adjustment to interest expense: We impute interest expense on the adjustment to debt. The rate is that inherent in the contract, or a rate estimated by the analyst based on the company's secured borrowing rates. In either case, it is applied to the average of the current period end, and the previous period end deferred VPP revenue balance.
- We add period-end reserve volumes related to VPPs back to reported reserves.
- Similarly, we add the oil and gas volumes produced to meet the VPP requirements to the company's production and sales statistics used to calculate per-barrel selling prices and lifting costs.
- Adjustment to operating cash flow: We reclassify cash proceeds from VPPs as

financing cash flows. Future cash flows will be adjusted (if practicable and data are available) upon delivery, to reflect the cash flows associated with the properties.

(Please see "Credit FAQ: Volumetric Production Payments For U.S. Oil And Gas Companies," published April 14, 2005, and "Oil And Gas Volumetric Production Payments: The Corporate Ratings Perspective," published Dec. 4, 2003, on RatingsDirect.)

Workers compensation/self insurance

Workers compensation systems provide compensation for employees injured in the course of employment. While schemes differ between jurisdictions, provisions may be made for payments in lieu of wages, compensation for economic losses (past and future), reimbursement for or payment of medical and like expenses, general damages for pain and suffering, and benefits payable to the dependents of workers killed during employment. (For example, U.S. coal mining companies, under the Federal Coal Mine Health and Safety Act, are responsible for medical and disability benefits to existing and former employees and their families who are affected by pneumoconiosis, better known as black lung disease.)

Workers compensation coverage may be provided through insurance companies, and thus is not a financial concern for the company. But, in certain instances and/or industries, employers assume direct responsibility for medical treatment, lost wages, etc.

In these cases, under U.S. GAAP or IFRS, the incurred liabilities usually are recorded on the company's balance sheet as other liabilities, based on an actuarially determined present value of known and estimated claims. Accordingly, these obligations represent a call on future cash flow, distinguishing them from many other, less-certain contingencies. They are analogous to postretirement obligations, which we also add to debt.

Treating the workers-compensation liability as debt affects many line items on the financial statements. Ideally, if there is sufficient disclosure available, we would adjust fully (in a manner akin to our post-retirement adjustments). In practice, the data are not available, so we reclassify these obligations, adjusted for tax, as debt. Similarly, we may also treat other analogous self-insurance-type liabilities as debt.

Adjustment procedures

Data requirements

- Net amount recognized as a liability for workers compensation obligations and for self-insurance claims.

Calculations

- Add amount recognized for workers compensation obligations (net of tax) and net amount recognized for self-insurance claims (net of tax) to debt. ■

Rating Each Issue

We assign two types of credit ratings—one to corporate issuers and the other to individual corporate debt issues (or other financial obligations). The first is called a Standard & Poor's corporate credit rating. It is our current opinion on an issuer's overall capacity to pay its financial obligations, i.e., its fundamental creditworthiness. This opinion focuses on the issuer's ability and willingness to meet its financial commitments on a timely basis. It generally indicates the likelihood of default regarding all financial obligations of the company, because, in most countries, companies that default on one debt type—or file for bankruptcy—virtually always stop payment on all debt types.

The corporate rating does not reflect any priority or preference among obligations. In the past, we published the "implied senior-most rating" of corporate obligors—a different term for precisely the same concept. "Default risk rating" and "natural rating" are additional ways of referring to this issuer rating.

(Generally, a corporate credit rating is published for all companies that have issue ratings—in addition to those companies that have no ratable issues, but request just an issuer rating. Where it is germane, both a local currency and foreign currency issuer rating are assigned.)

We also assign credit ratings to specific issues. In fact, the vast majority of credit ratings pertain to specific debt issues. Long-term issue ratings are a blend of default risk (sometimes referred to as "timeliness") and the recovery prospects (loss given default, or LGD) associated with the specific debt being rated. Debt with relatively good recovery prospects—especially well-secured debt—is rated above the corporate credit rating; debt with relatively poor prospects for such loss-given-default—especially junior debt—is rated below the corporate credit rating. Notching does not apply to short-term ratings *(see Commercial Paper chapter of this book)*.

Recovery ratings were added in 2003. These ratings address only recovery prospects, using a scale of one to six, rather than the letter ratings.

Notching Down; Notching Up

The practice of differentiating issues in relation to the issuer's fundamental creditworthiness is known as "notching." Issues are notched up or down from the corporate credit rating level. Payment on time as promised obviously is critical with respect to all debt issues. The potential for recovery in the event of a default—i.e., ultimate recovery, albeit delayed—also is important, but timeliness is the primary consideration. That explains why issue ratings are still anchored to the corporate credit rating. They are notched—up or down—from the corporate credit rating in accordance with established guidelines explained here.

As default risk increases, the concern over what can be recovered takes on greater relevance and, therefore, greater rating significance. Accordingly, the loss-given-default aspect of ratings is given more weight as one moves down the rating spectrum. For example, subordinated debt can be rated up to two notches below a non-investment grade corporate credit rating, but one notch at most if the corporate credit rating is investment grade. (In the same vein, issues of companies with a 'AAA' rating need not be notched at all.)

For investment-grade companies, we seek to differentiate those financial obligations judged to have materially inferior recovery prospects by virtue of being unsecured or subordinated—either contractually or structurally. Priority in bankruptcy is considered in broad terms; there is no attempt to specify a default scenario.

In the speculative-grade categories, we do seek to predict specific recovery levels based on full-blown default-scenario modeling. Because any default would presumably be less distant in time than for investment-grade companies, it is more reasonable to analyze a specific anticipated default scenario, with associated asset mix and realizable values. When such a rigorous recovery analysis is performed, we assign a recovery rating and base the notching on the specific outcome. We focus on a central tendency of approximately 50%. Therefore, issues with recovery rates significantly above 50% are rated above the corporate rating; conversely, issues recovering significantly less than 50% are rated below the corporate rating. We go into greater detail in "Speculative-grade").

Notching relationships underlying issue ratings are subject to review and change when actual developments vary from expectations. Changes in notching do not necessarily have to be accompanied by changes in default risk.

Notching guidelines are a function of the bankruptcy law and practice in the legal jurisdiction that governs a specific instrument. For example, distinguishing between senior and subordinated debt can be meaningless in India, where companies may be allowed to continue paying even common dividends at the same time they are in default on debt obligations; accordingly, notching is not applied in India. The majority of legal systems broadly follow the practices underlying our criteria for notching—but it always is important to be aware of nuances of the law as they pertain to a specific issue.

Preferred stock

Preferred stock carries greater credit risk than debt in two important ways: The dividend is at the discretion of the issuer, and the preferred represents a deeply subordinated claim in the event of bankruptcy. Prior to 1999, Standard & Poor's used a separate preferred stock scale. In February 1999, the debt and preferred stock scales were integrated.

Accordingly, now, preferred stock generally is rated below subordinated debt. When our credit rating on a company is investment grade, its preferred stock is rated two notches below the corporate credit rating. For example, if the corporate credit rating is 'A+', the preferred stock would be rated 'A-'. (In case of a 'AAA' corporate credit rating, the preferred stock would be rated 'AA+'.) When the corporate credit rating is non-investment grade, the preferred stock is rated at least three notches (one rating category) below the corporate credit rating. Deferrable payment debt is treated identically to preferred stock, given subordination and the right to defer payments of interest.

There are situations in which the dividend is especially jeopardized, so notching would exceed the guidelines above. For example, state charters restrict payment when there is a deficit in the equity account. This can occur following a write-off, even while the company is healthy and possesses ample cash to continue paying. Similarly, covenants in debt instruments can endanger payment of dividends, even while there is a capacity to pay.

In all cases, the risk of deferral of payments is analyzed from a pragmatic, rather than a legal, perspective. If a company defers a payment or passes on a preferred dividend, it is tantamount to default on the preferred issues. The rating is changed to 'D' once the payment date has passed. The rating usually would be lowered to 'C' in the interim, to the extent nonpayment can be anticipated—e.g., if the company were to announce that its directors failed to declare the preferred dividend. Whenever a company resumes paying preferred dividends but remains in arrears with respect to payments it skipped, the rating is, by definition, 'C'.

Convertible preferred/equity units

Some securities provide for mandatory conversion into common stock of a company. Such securities vary with respect to the formula for sharing potential appreciation in share value. In the interim, these securities represent a subordinated debt or preferred stock claim. Other offerings package a short-life debt or preferred stock with a deferred common stock purchase contract to achieve similar economics.

Ratings on the issue address primarily the likelihood of interim payments and the solvency of the company at the time of conversion to enable it to honor its obligation to deliver the shares. These ratings do not address the amount or value of the common stock investors ultimately will receive. The equity risk that pertains is reflected merely by limiting the rating to the equivalent of the company's preferred equity securities. (We once highlighted this risk by appending an "r" to the ratings of these hybrid securities, but now rely on the market's familiarity with such instruments and their terms.)

Reflecting Recovery In Issue Ratings

If we can confidently project recovery prospects exceeding 70% for an individual security, that issue is typically rated higher than the corporate rating; conversely, if we project recovery for a given security to be under 30%, the issue is typically rated lower than the corporate rating. When we cannot confidently model absolute recovery because of jurisdictional issues or because the corporate credit rating is investment-grade and the issue is unsecured, we notch down when a debt issue's junior standing, relative to other debt issues of the company, indicates relatively poor recovery prospects.

The weighting of recovery aspects in issue ratings also varies as the potential for default becomes more meaningful, as explained below.

Investment grade

For investment-grade companies, notching relationships are based on broad guidelines that combine consideration of asset protection and ranking. The guidelines are designed to identify material disadvantage for a given issue by virtue of the existence of better-positioned obligations. The analyst does not seek to predict specific recovery levels, which would involve knowing the exact asset mix and values at a point well into the future. Therefore we do not generally perform a fundamental recovery analysis, given the difficulty of doing meaningful default scenario analysis while the company is still so strong.

(For example, we would not presume that default occurs while the company's capital structure remains roughly the same—as we generally do in the recovery analysis of speculative grade companies. With respect to currently strong credits—with relatively unburdened balance sheets—such an approach would be inappropriate. Indeed, currently, we typically do not assign recovery ratings for debt issues of investment-grade corporates—with the exception of utility first mortgage bonds.)

Rather, we use a rule-of-thumb approach to identify debt issues with inferior recovery prospects—or, for consideration of adding notches, we use discrete asset valuations if there is collateral (modified somewhat in the case of regulated utilities).

Rating below the corporate credit rating: "Notching down"

When a debt issue is judged to be junior to other debt issues of the company, and thereby to have relatively poor recovery prospects, that issue is notched down from the corporate credit rating. As a matter of rating policy, the differential is limited to one rating designation in the investment-grade categories given the critical role of timeliness for investment grade debt. Loss-given-default is just less significant in the scheme of things for investment grade—leading to less weight given to recovery; investors are focused on getting paid in the first place.

Whenever a threshold percentage of the company's assets would first be used to satisfy other claims, this translates into a meaningful disadvantage for the "junior" creditors. The threshold for notching is reached when more-senior claims cover over 20% of the assets (unless less-valuable assets make up the collateral or there exist mitigating factors, such as upstream guarantees).

While we do not make specific judgments regarding the level of absolute recovery for investment-grade debt, the material disadvantage of junior issues is designed to roughly correspond to the 30% absolute-recovery benchmark that applies for speculative-grade notching. More often than not, junior debt recovers less than 30% (although this figure may vary by jurisdiction).

The threshold level takes into account that it normally takes more than $1 of book assets—as valued today—to satisfy $1 of priority debt. In the case of secured debt—which limits the priority to the collateral pledged—the remaining assets are still less likely to be sufficient to repay the unsecured debt, inasmuch as the collateral ordinarily consists of the company's better assets and often substantially exceeds the amount of the debt.

Moreover, in all likelihood, there will be additional debt by the time of default, as pointed out above. Since such debt—as well as the refinancing of existing debt—will be incurred as the company approaches default, it is more likely to be on a secured basis (or directly to the entity that holds the operating assets, in the case of an operating company/holding company structure).

To the extent that certain obligations have a priority claim on the company's assets, lower-ranking obligations are at a disadvantage because a smaller pool of assets will be available to satisfy the remaining claims. As mentioned above, debt can be junior by virtue of being contractually subordinated—that is, the terms of the issue specifically provide that debt holders will receive recovery in a bankruptcy only after the claims of other creditors have been satisfied.

Another case is when the issue is unsecured, while assets representing a significant portion of the company's value collateralize secured borrowings. (If the collateral that secures a particular debt issue is of dubious value, while the more valuable collateral is pledged to another loan, even secured debt may be notched down from the corporate credit rating.)

A third form of disadvantage can arise if a company conducts its operations through an operating subsidiary/holding-company structure. In this case, if the whole group is bankrupt, creditors of the subsidiaries—including holders of even contractually subordinated debt—would have the first claim to the subsidiaries' assets, while creditors of the parent would have only a junior claim, limited to the residual value of the subsidiaries' assets remaining after the subsidiaries' direct liabilities have been satisfied. The disadvantage of parent-company creditors owing to the parent/subsidiary legal structure is known as "structural subordination." Even if the group's operations are splintered among many small subsidiaries, the individual debt obligations of which have only dubious recovery prospects, the parent-company creditors may still be disadvantaged compared with a situation in which all creditors would have an equal claim on the assets.

If a company has an atypical mix of assets, the 20% threshold could be higher or lower to reflect the relative amounts of better or worse assets. Goodwill especially is suspect, considering its likely value in a default scenario. In applying the notching guidelines, Standard & Poor's generally eliminates from total assets goodwill in excess of a normal amount—10% of total adjusted assets. As distinct from goodwill, intangibles are considered potentially valuable—for example, established brands in the consumer products sector. We do not, however, perform detailed asset appraisals or attempt to postulate specifically about how market values might fluctuate in a hypothetical stress scenario (except in the case of secured debt).

The concept behind these thresholds is to measure material disadvantage with respect to the various layers of debt. At each level, as long as the next layer of debt still enjoys plenty of asset coverage, we do not consider the priority of the top layers as constituting a real disadvantage for the more junior issuers. Accordingly, the nature of the individual company's asset is important: If a company has an atypical mix of assets, the thresholds could be higher or lower to reflect the relative amounts of better or worse assets.

The relative size of the next layer of debt also is important. If the next layer is especially large—in relation to the assets assumed to remain after satisfying the more senior layers—then coverage is impaired. There are numerous LBOs financed with outsized issues just below the senior layers. Although the priority debt may be small (below the threshold levels), it poses a real disadvantage for junior issues: given the paucity of coverage remaining, the junior debt should be notched down.

One other note to keep in mind is that "absolute trumps relative." If for structural or other issue-specific (or jurisdiction specific) reasons we can confidently anticipate recovery above 30% (and below 70%), we would equate the issue rating with the corporate credit rating, regardless of the result of the priority debt calculation. Similarly, if there were structural, issue-specific, or jurisdiction-specific reasons to anticipate recovery below 30%, we would rate the issue one notch below the corporate credit rating. These absolute recovery ranges are similar to those used for speculative-grade issue rating guidelines where we assign recovery ratings.

Application of guidelines

In applying the guidelines above, lease obligations—whether capitalized in the company's financial reporting or kept off balance sheet as operating leases as priority debt—and the related assets are included on the asset side. Similarly, sold trade receivables and securitized assets are added back, along with an equal amount of priority debt. Other creditors are just as disadvantaged by such financing arrangements as by secured debt. In considering the surplus cash and marketable securities of companies that presently are financially healthy, we assume neither that the cash will remain available in the default scenario, nor that it will be totally dissipated, but rather that, over time, this cash will be reinvested in operating assets that mirror the company's current asset base, subject to erosion in value of the same magnitude.

Local- and foreign-currency issue ratings. In determining local-currency issue ratings, the point of reference is the local-currency corporate credit rating: local-currency issue ratings may be notched down one notch from the local-currency corporate credit rating in the case of investment-grade issuers, or one or two notches in the case of speculative-grade issuers. A foreign-currency corporate credit rating on a company is sometimes lower than the local-currency corporate credit rating, reflecting the risk that a sovereign government could take actions that would impinge on the company's ability to meet foreign-currency obligations. But junior foreign-currency issues are not notched down from the foreign-currency corporate credit rating, because the government action would apply regardless of the senior/junior character of the debt. Of course, the issue would never be rated higher than if it had been denominated in local currency. For example, if the local-currency corporate credit rating on a company were 'BB+' and the foreign-currency corporate credit rating were 'BB-', subordinated foreign currency-denominated issues could be rated 'BB-'. But, if the local-currency corporate credit rating were 'BB+' and the foreign currency corporate credit rating was 'BB', the subordinated foreign-currency denominated issues would be rated 'BB-', as would the subordinated local-currency denominated issues.

Rating above the corporate credit rating: "Notching up"

Since we generally do not perform specific default scenario modeling for investment-grade companies, identifying issues with superior recovery characteristics usually relies on security provisions of a specific issue. Candidates for notching up are secured debt issues, where collateral consists of assets with a well-established track record with respect to recovery, such as first mortgage bonds of regulated utilities.

As explained above, the weight given to recovery in assigning issue ratings diminishes as one moves up the rating spectrum. When a company's rating is in the 'BBB' category, its well-secured debt is rated one or two notches above the corporate rating, depending on the extent of the collateral coverage. For the 'A' category, the maximum addition is limited to one notch—and this applies only when full recovery is anticipated. For 'AAA' and 'AA' categories, notching up is phased out entirely.

Structural subordination

At times, a parent and its affiliate group have distinct default risks. The difference in risk may arise from covenant restrictions, regulatory oversight, or other considerations. This is the norm for holding companies of insurance operating companies and banks. In such situations, there are no fixed limits governing the gaps between corporate credit ratings of the parent and its subsidiaries. The holding company has higher default risk, apart from post-default recovery distinctions. If such a holding company issued both senior and junior debt, its junior obligations would be notched relative to the holding company's corporate credit rating by one or two notches.

Often, however, a parent holding company with one or more operating companies is viewed as a single economic entity. When the default risk is considered the same for the parent and its principal subsidiaries, they are assigned the same corporate credit rating. Yet, in a liquidation, holding-company creditors are entitled only to the residual net worth of the operating companies remaining after all operating company obligations have been satisfied. Parent-level debt issues are notched down to reflect structural subordination when the priority liabilities create a material disadvantage for the parent's creditors, after taking into account all mitigating factors. In considering the appropriate rating for a specific issue of parent-level debt, priority liabilities encompass all third-party liabilities (not just debt) of the subsidiaries—including trade payables, pension and retiree medical liabilities, and environmental liabilities—and any relatively better positioned parent-level liabilities. (For example, parent-level borrowings collateralized by the stock of the subsidiaries would be disadvantaged relative to subsidiary liabilities, but would rank ahead of unsecured parent-level debt.) Potential mitigating factors include:

Guarantees

Guarantees by the subsidiaries of parent-level debt (i.e., upstream guarantees) may overcome structural subordination by putting the claims of parent company creditors on a pari passu basis with those of operating company creditors. Such guarantees have to be enforceable under the relevant national legal system(s), and there most be no undue concern regarding potential allegations of fraudulent conveyance. Although joint and several guarantees from all subsidiaries provide the most significant protection, several guarantees by subsidiaries accounting for a major portion of total assets would be sufficient to avoid notching of parent debt issues in most cases.

The legal analysis outcome depends on the specific fact pattern, not legal documentation—so one cannot standardize the determination. But, if either the guarantor company received value or was solvent for a sufficiently long period subsequent to issuing the guarantee, the upstream guarantee should be valid. Accordingly, we consider upstream guarantees valid if any of these conditions are met:

- The proceeds of the guaranteed obligation are provided (downstreamed) to guarantor. It does not matter whether the issuer downstreams the money as an equity infusion or as a loan. Either way, the financing benefits the operations of the subsidiary which justifies the guarantee;
- The legal risk period—ordinarily, one or two years from entering into the guarantee—has passed;
- There is a specific analytical conclusion that there is little default risk during the period that the guarantee validity is at risk; or
- The rating of the guarantor is at least 'BB-' in jurisdictions that involve a two-year risk,

or at least 'B+' in jurisdictions with one year risk.

Operating assets at the parent
If the parent is not a pure holding company, but rather also directly owns certain operating assets, this gives the parent's creditors a priority claim to the parent-level assets. This offsets, at least partially, the disadvantage that pertains to being structurally subordinated with respect to the assets owned by the subsidiaries.

Diversity
When the parent owns multiple operating companies, more liberal notching guidelines may be applied to reflect the benefit the diversity of assets might provide. The threshold guidelines are relaxed (but not eliminated) to correspond with the extent of business and/or geographic diversification of the subsidiaries. For bankrupt companies that own multiple, separate business units, the prospects for residual value remaining for holding company creditors improve as individual units wind up with shortfalls and surpluses Also, holding companies with diverse businesses—in terms of product or geography—have greater opportunities for dispositions, asset transfers, or recapitalization of subsidiaries. If, however, the subsidiaries are operationally integrated, economically correlated, or regulated, the company's flexibility to reconfigure is more limited.

Concentration of debt
If a parent has a number of subsidiaries, but the preponderance of subsidiary liabilities are concentrated in one or two of these, e.g., industrial groups having finance or trading units, this concentration of liabilities can limit the disadvantage for parent-company creditors. Although the net worth of the leveraged units could well be eliminated in the bankruptcy scenario, the parent might still obtain recoveries from its relatively unleveraged subsidiaries. In applying the notching guideline in such cases, it may be appropriate to eliminate the assets of the leveraged subsidiary from total assets, and its liabilities from priority liabilities. The analysis then focuses on the assets and liabilities that remain, and the standard notching guideline must be substituted by other judgments regarding recovery prospects.

Downstream loans
If the parent's investment in a subsidiary is not just an equity interest, but also takes the form of downstream senior loans, this may enhance the standing of parent-level creditors because they would have not only a residual claim on the subsidiary's net worth, but also a debt claim that could be pari passu with other debt claims. However, most intercompany claims are subject to equitable subordination and/or other elimination in the bankruptcy process. Such assessment of downstream advances must take into account the applicable legal framework. (On the other hand, if the parent has borrowed funds from its subsidiaries, the resulting intercompany parent-level liability could further dilute the recoveries of external parent-level creditors.)

Adjustments
We eliminate from the notching calculations subsidiaries' deferred tax assets and liabilities and other accounting accruals and provisions that are not likely to have clear economic meaning in a default.

Speculative grade
For speculative grade issuers, we perform a fundamental recovery analysis, which is communicated via our recovery ratings. The different levels of recovery are factored into our debt issue ratings by adding or subtracting notches from the corporate credit rating *(see table 6)*.

Recovery ratings assess a debt instrument's ultimate prospects for recovery of estimated principal and pre-petition interest (i.e., interest accrued but unpaid at the time of default) given a simulated payment default. Our recovery methodology focuses on estimating the percentage of recovery that debt investors would receive at the end of a formal bankruptcy proceeding or an informal out-of-court restructuring. Lender recoveries could be in the form of cash, debt or equity securities of a reorganized entity, or some combination thereof.

We focus on nominal recovery (rather than discounted present value recovery) because we believe discounted recovery is better identified independently by market participants who can apply their own preferred discount rate to our nominal recovery. (However, in jurisdictions with anticipated workout periods of longer than two to three years, we factor the delay into both recovery ratings and issue ratings to account for the time value of money and the inherent incremental uncertainty.)

While informed by historical recovery data, our recovery ratings incorporate fundamental deal-specific, scenario-driven, forward-looking analysis. They consider the impact of key structural features, inter-creditor dynamics, the nature of insolvency regimes, multi-jurisdictional issues, in the context of a simulated default.

We acknowledge that recovery analysis (including default modeling, valuation, and restructuring dynamics) is complex and does not lend itself to precise or certain predictions. Outcomes invariably involve unforeseen events and are subject to extensive negotiations that are influenced by the subjective judgments, negotiating positions, and agendas of the various stakeholders. Even so, we believe our methodology of focusing on a company's unique and fundamental credit risks—together with the composition and structure of its debt, legal organization, and non-debt liabilities—provides valuable insight into creditor recovery prospects.

In this light, our recovery ratings are intended to provide educated approximations of post-default recovery rates, rather than exact forecasts. Recovery ratings, when viewed together with a company's risk of default as estimated by our corporate credit rating, can help investors evaluate a debt instrument's risk/reward characteristics and determine their expected return.

Jurisdiction-specific adjustments for recovery and issue ratings

Full-blown, fundamental recovery analysis is limited to jurisdictions where insolvency regimes are reasonably well established and sufficient precedent and data are available. In other jurisdictions, we do not assign recovery ratings—and the basis for rating a specific issue different from than the corporate credit rating is similar to that used in investment-grade situations. That is, we employ a simple rule-of-thumb approach to identify issues that are junior—and thereby materially disadvantaged with respect to recovery prospects. If claims that come ahead of a given debt issue equal 15% of assets, we subtract one notch from the corporate credit rating level; if such priority claims reach the 30% level, we subtract two notches. We do not rate issues more than two notches below the corporate

Table 6 Recovery Rating Scale And Issue Rating Criteria

(For issuers with a speculative-grade corporate credit rating)

Recovery rating	Recovery description	Recovery expectations (%)*	Issue rating notches relative to corporate credit rating
1+	Highest expectation, full recovery	100	+3
1	Very high recovery	90–100	+2
2	Substantial recovery	70–90	+1
3	Meaningful recovery	50–70	0
4	Average recovery	30–50	0
5	Modest recovery	10–30	-1
6	Negligible recovery	0–10	-2

*Recovery of principal plus accrued but unpaid interest at the time of default. ¶Very high confidence of full recovery resulting from significant overcollateralization or strong structural features.

credit rating on the basis of inferior recovery considerations.

We are in the process of reviewing all significant jurisdictions around the world to assess how insolvency proceedings in practice affect post-default recovery prospects and to consistently incorporate jurisdiction-specific adjustments. With the help of local insolvency practitioners, we assess each jurisdiction's creditor friendliness—in theory as well as in practice (about 30 jurisdictions have been assessed to date).

The four main factors that shape our analysis of the jurisdictions' creditor friendliness are:

- Security,
- Efficiency and control,
- Adherence to priorities, and
- Time to resolution.

Based on these factors, we classify the reviewed countries into three categories, according to their creditor-friendliness. This classification enables us to make jurisdiction-specific adjustments to our recovery analysis. We cap both recovery ratings and the differential between the issuer credit and debt issue ratings in countries with debtor-friendly insolvency regimes. *(See "Jurisdiction-Specific Adjustments To Recovery And Issue Ratings," published July 5, 2007, on RatingsDirect.)*

Recovery Methodology For Industrials

Recovery analytics for industrial issuers has three basic components: determining the most likely path to default for a company; valuing the company following default; and distributing that value to claimants that we identify, based upon the relative priority of each claimant.

Establishing a simulated path to default

This step is a fundamental; we must first understand the forces most likely to cause a default before we can estimate a level of cash flow at default or value a company. This step draws on the company and sector knowledge of our credit analysts to formulate and quantify the factors most likely to cause a company to default, given its unique business risks and financial risks.

At the outset of this process, we deconstruct the borrower's cash flow projections to understand management's general business, industry, and economic expectations. Once we understand management's view, we make appropriate adjustments to key economic, industry, and firm specific factors to simulate a payment default. While we recognize that there are many possible factors—both foreseen and unforeseen—that could lead to a default, we focus on the key operating factors that would most likely contribute to default.

Forecasting cash flow at default

The simulated default scenario is our assessment of the borrower's most likely path to a hypothetical payment default. The "insolvency proxy" is the point along that path that the company would default. The insolvency proxy is ordinarily defined as the point at which funds available plus free cash flow is exceeded by fixed charges.

The terms in this equation are:

Funds available. The sum of balance sheet cash and revolving credit facility availability (in excess of the minimal amount a company needs to operate its business at its seasonal peak).

Free cash flow. EBITDA in the year of default, less a minimal level of required maintenance capital expenditures, less cash taxes, plus or minus changes in working capital. For default modeling and recovery estimates, our EBITDA and free cash flow estimates ignore noncash compensation expenses and do not use our adjustments for operating leases.

Fixed charges. The sum, in the year of default, of:

- Scheduled principal amortization. Bullet or ballooning maturities are not treated as fixed charges, because lenders typically would refinance these amounts as long as a company can otherwise comfortably service its fixed charges.
- Required cash interest payments, including assumed increases to LIBOR rates on floating-rate debt and to the margin charged on debt obligations that have pricing grids or maintenance financial covenants; and
- Other cash payments the borrower is either contractually or practically obligated to pay that are not already captured as an operating expense. (Lease payments, for

example, are accounted for within free cash flow and are not considered a fixed charge.)

A projected default may occur even if fixed charges are fully covered in a few special circumstances:

- Strategic bankruptcy filings, when a borrower may attempt to take advantage of the insolvency process primarily to obtain relief from legal claims or onerous contracts;
- When a borrower in distress may rationally be expected to retain a large amounts of cash (e.g., to prepare for a complex, protracted restructuring; if it is in a very capital-intensive industry; if it is in a jurisdiction that does not allow for superpriority standing for new credit in a post-petition financing); or
- When a borrower's financial covenants have deteriorated beyond the level at which even the most patient lender could tolerate further amendments or waivers.

Free cash flow is not necessarily equal to the level at point of default, though. Cash flow may decline below the insolvency proxy if the borrower's operating performance is expected to continue to deteriorate due to whatever competitive and economic conditions are assumed in the simulated default scenario. In any event, we attempt to identify a level of cash flow as one basis for our valuation.

Determining valuation

We consider a variety of valuation methodologies, including market multiples, discounted cash flow (DCF) modeling, and discrete asset analysis. The market multiples and DCF methods are used to determine a company's enterprise value as a going concern. This is generally the most appropriate approach when our simulated default and recovery analysis indicates that the borrower's reorganization (or the outright sale of the ongoing business or certain segments) is the most likely outcome of an insolvency proceeding.

We use discrete asset valuation most often for industries in which this valuation approach is typically used, or when the simulated default scenario indicates that the borrower's liquidation is the most likely outcome of insolvency.

If a company is expected to reorganize, but certain creditors hold collateral consisting of only particular assets, then enterprise value is inappropriate—and we assess the collateral based in its discrete values.

Market multiples

The key to valuing a company using a market-multiples approach is to select appropriate comparable companies, or comps. The analysis should include several comps similar to the company being valued with respect to business lines, geographic markets, margins, revenue, capital requirements, and competitive position. Of course, an ideal set of comps does not always exist, so analytical judgment often is required to adjust for differences in size, business profiles, and other attributes. In addition, in the context of a recovery analysis, the multiples must consider the competitive and economic environments assumed in our simulated default scenario, which are often very different than present conditions. As a result, our analysis strives to consider a selection of multiples and types of multiples.

Ideally, we are interested in multiples for similar companies that have reorganized because of circumstances consistent with our simulated default scenario. In practice, however, the existence of such "emergence" multiple comps are rare. As a result, our analysis often turns to transaction or purchase multiples for comparable companies, because these generally are more numerous. With transaction multiples, we try to use forward multiples (purchase price divided by projected EBITDA), rather than trailing multiples (purchase price divided by historical EBITDA), because we believe forward multiples, which incorporate the benefit of perceived cash flow synergies used to justify the purchase price, provide a more appropriate reference point. In addition, trading multiples for publicly traded companies can be useful because they allow us to track how multiples change over economic and business cycles. This is especially relevant for cyclical industries and for sectors entering a different stage of development, or experiencing changing competitive conditions.

A selection of multiples helps match our valuation with the conditions assumed in our simulated default scenario. For example, a company projected to default in a cyclical trough may warrant a higher multiple than one expected to default at a cyclical midpoint. Further, two companies in the same industry may merit meaningfully different multiples if one is highly levered and at risk of default from relatively normal competitive stresses, while the other is unlikely to default unless there is a large unexpected fundamental deterioration in the cash flow potential of the business model (which could make historical sector multiples irrelevant).

Our multiples analysis may also consider alternative industry-specific multiples—such as subscribers, hospital beds, recurring revenue, etc.—where appropriate. Alternatively, such metrics may serve as a check on the soundness of a valuation that relied on an EBITDA multiple, DCF, or discrete asset approach.

Discounted cash flow (DCF)

Our valuation is based on the long-term operating performance of the reorganized company. We use a perpetuity growth formula, which contemplates a long-term steady-state growth rate deemed appropriate for the borrower's business. However, when applicable, we start with specific annual cash flow forecasts for a period of time following reorganization, while relying on the perpetuity growth formula for subsequent periods.

Discrete asset valuation

We value the relevant assets by applying industry-and asset-specific advance rates or third-party appraisals.

Identifying and estimating the value of debt and nondebt claims

After valuing a company, we identify and quantify the debt obligations and other material liabilities that would be expected to have a claim against the company. Potential claims fall into three broad categories:

- Principal and accrued interest on all debt outstanding at the point of default, whether issued at the operating company, subsidiary, or holding company level;
- Bankruptcy-related claims, such as debtor-in-possession (DIP) financing and administrative expenses for professional fees and other bankruptcy costs;
- Other nondebt claims, such as taxes payable, certain securitization programs, trade payables, deficiency claims on rejected leases, litigation liabilities, and unfunded post-retirement obligations.

Our analysis of these claims and their potential values takes into consideration each borrower's particular facts and circumstances, as well as the expected impact on the claims as a result of our simulated default scenario.

We estimate debt outstanding at the point of default by reducing term loans by scheduled amortization up to the point of our simulated default. We assume that all committed debt facilities, such as revolving credit facilities and delayed draw term loans, are fully drawn. For asset-based lending (ABL) facilities, we consider whether the borrowing base formula would allow the company to fully draw the facility in a simulated default scenario. For letters of credit, especially those issued under dedicated synthetic letter of credit tranches, we assess whether these contingent obligations are likely to be drawn.

Our estimate of debt outstanding at default also includes an estimate of prepetition interest, which is calculated by adding six months of interest (based on historical data from Standard & Poor's LossStats® database) to our estimated principal amount at default. The inclusion of pre-petition interest makes our recovery analysis more consistent with banks' credit risk capital requirements under the Basel II Framework.

Our analysis focuses on the recovery prospects for the debt instruments in a company's current or pro forma debt structure, and generally does not make estimates for other debt that may be issued prior to a default. We feel that this approach is prudent and more relevant to investors because the amount and composition of any additional debt (secured, unsecured, and/or subordinated) may materially impact lender recovery rates, and it is not possible to know these particulars in advance. Further, incremental debt added to a company's capital structure may materially affect its probability of default, which could in turn affect all aspects of our recovery analysis (i.e., the most likely path to default, valuation given default, and loss given default). Consequently, changes to a company's debt structure are treated as events that require a reevaluation of our default and recovery analysis.

Still, we take into account the potential for additional debt by limiting the recovery ratings assigned to unsecured debt—and, in turn, the notches above the corporate rating that might be added. For companies with a 'B' category rating, the recovery rating would ordinarily be limited to '2'. For companies in the 'BB' category we would limit the recovery ratings assigned to unsecured issues to '3'. (Because they are further from potential default, there is a greater likelihood that interim change of their capital structure would occur.)

Also we add more debt to the extent that this is consistent with our specific expectations for a given issuer. Similarly, we may assume the repayment of near-term debt maturities—without refinancing—if the company is expected to retire these obligations and has the liquidity to do so. Furthermore, revolving credit facilities with near-term maturities are generally assumed to roll over with similar terms.

Determining distribution of value

Distributions are assumed to follow a waterfall approach that reflects the relative seniority of the claimants, reflecting the specific laws, customs, and insolvency regime practices for the relevant jurisdictions for a company. In the U.S., our general assumption of the relative priority of claimants is:

- Super-priority claims, such as DIP financing;
- Administrative expenses;
- Federal and state tax claims;
- Senior secured claims;
- Junior secured claims;
- Senior unsecured debt and nondebt claims;
- Subordinated claims;
- Preferred stock; and
- Common stock.

However, this priority of claims is subject to two critical caveats:

- The beneficial position of secured creditor claims, whether first-priority or otherwise, is only valid to the extent that the collateral supporting such claims is equal to, or greater than, the amount of the claim. If the collateral value is insufficient to fully cover a secured claim, then the uncovered amount or deficiency balance will be pari passu with all other senior unsecured claims.
- Structural issues may alter the priority of certain claims against specific assets or entities in an organization based on the company's legal entity structure and the relevant terms and conditions of the debt instruments.

The recovery prospects for different debt instruments of the same type (senior secured, senior unsecured, senior subordinated, etc.) might be very different, depending on the structure of the transactions. We review a company's debt and legal entity structure, the terms and conditions of the various debt instruments as they pertain to borrower and guarantor relationships, collateral pledges and exclusions, facility amounts, covenants, and debt maturities. In addition, we must understand the breakout of the company's cash flow and assets as it pertains to its legal organizational structure, and consider the effect of key jurisdictional and intercreditor issues. Key structural issues to explore include identifying:

- Higher priority liens on specific assets by forms of secured debt such as mortgages, industrial revenue bonds, and ABL facilities;
- Non-guarantor subsidiaries (domestic or foreign) that do not guarantee a company's primary debt obligations or provide asset pledges to support the company's secured debt;
- Claims at non-guarantor subsidiaries that will have a higher priority (i.e., a structurally superior) claim on the value related to such entities;
- Material exclusions to the collateral pledged to secured lenders, including the lack of asset pledges by foreign subsidiaries or the absence of liens on significant domestic assets, including the stock of foreign or domestic nonguarantor subsidiaries (whether due to concessions demanded by and grant-

ed to the borrower, poor transaction structuring, regulatory restrictions, or limitations imposed by other debt indentures); and

- Whether a company's foreign subsidiaries are likely to file for bankruptcy in their local jurisdictions as part of the default and restructuring process.

While our analysis typically reduces the enterprise value by the amount of secured claims in accordance with its priority, there may be meaningful excess collateral value that is available to other creditors, especially those with a second lien. For example, this is often the case when secured debt collateralized by a first lien on all noncurrent assets also takes a second-priority lien on working capital assets that are already pledged to support an asset-based revolving credit facility.

Significant domestic or foreign nonguarantor entities must be identified because these entities have not explicitly promised to repay the debt. Thus, the portion of enterprise value derived from these subsidiaries does not directly support the rated debt. As a result, debt and certain nondebt claims at these subsidiaries have a structurally higher priority claim against the subsidiary value. Accordingly, the portion of the company's enterprise value stemming from these subsidiaries must be estimated and treated separately in the distribution of value to creditors. This requires an understanding of the breakout of a company's cash flow and assets. Because these subsidiaries are still part of the enterprise being evaluated, any equity value that remains after satisfying the structurally superior claims would be available to satisfy other creditors of the entities that own these subsidiaries. Well-structured debt will often include covenants to restrict the amount of structurally superior debt that can be placed at such subsidiaries. Further, well-structured secured debt will take a lien on the stock of such subsidiaries to ensure a priority interest in the equity value available to support other creditors. In practice, the pledge of foreign subsidiary stock owned by U.S. entities is usually limited to 65% of voting stock for tax reasons. The residual value that is not captured by secured lenders through stock pledges would be expected to be available to all senior unsecured creditors on a pro rata basis.

Material assets (other than whole subsidiaries or subsidiary stock) not pledged to support secured debt would be shared by all senior unsecured creditors on a pro rata basis.

An evaluation of whether foreign subsidiaries would also be likely to file for bankruptcy is also required, because this would likely increase the cost of the bankruptcy process and create potential multijurisdictional issues that could impact lender recovery rates. The involvement of foreign courts in a bankruptcy process presents a myriad of complexities and uncertainties. For these same reasons, however, U.S.-domiciled borrowers that file for bankruptcy seldom also file their foreign subsidiaries without a specific benefit or reason for doing so. Consequently, we generally assume that foreign subsidiaries of U.S. borrowers do not file for bankruptcy unless there is a compelling reason to assume otherwise, such as a large amount of foreign debt that needs to be restructured to enable the company to emerge from bankruptcy. When foreign subsidiaries are expected to file bankruptcy, our analysis will be tailored to incorporate the particulars of the relevant bankruptcy regimes.

Intercreditor issues may affect the distribution of value and result in deviations from absolute priority (i.e., maintenance of the priority of the claims, including structural considerations, so that a class of claims will not receive any distribution until all classes above it are fully satisfied) In practice, Chapter 11 bankruptcies are negotiated settlements and the distribution of value may vary somewhat from the ideal implied by absolute priority for a variety of inter-creditor reasons, including, in the U.S., "accommodations" and "substantive consolidation."

Accommodations refer to concessions granted by senior creditors to junior claimants in negotiations to gain their cooperation in a timely restructuring. We generally do not explicitly model for accommodations because it is uncertain whether any concessions will be granted, if those granted will ultimately have value (e.g., warrants as a contingent equity claim), or whether the value will be material enough to meaningfully affect our projected recovery rates.

Substantive consolidation—in its pure form—represents a potentially drastic deviation from the ordering of priorities and distribution of value in bankruptcy plans of reorganization. In a true "legal" substantive consolidation, the assets and liabilities of an affiliated corporate group are collapsed into a single legal entity. This effectively would eliminate the credit support provided by structural priority, by treating creditors of the parent pari passu with creditors of operating units. However, true substantive consolidation is a rarely implemented, discretionary judicial doctrine. Our analysis relies on the low likelihood of true substantive consolidation, though we acknowledge that this risk could affect recoveries in certain cases.

Many more reorganization bankruptcy plans do involve a consolidation of a more limited nature. These consolidations do not radically affect the priority of external creditor claims—but do eliminate many inter-company claims, guaranties, and distributions and simplify the plan approval process and distributions to creditors under the plan. These "deemed" consolidations typically promote the resolution of complex multi-party negotiations and settlements along the lines of the relative legal priorities and bargaining strengths of creditors.

The bankruptcy process involves an inherent element of uncertainty. Indeed, the impact of deemed consolidation on recovery can vary. The extent to which more-senior creditors are willing to make concessions to more junior creditors to keep the process moving smoothly and to arrive at a consensual plan is impossible to predict.

However, in practice, the result of court-ordered consolidation is not sufficiently material enough of the time to be considered in our recovery rating assignments.

Surveillance of recovery ratings

Our recovery analysis at origination is unlikely to identify all of the actual claims at bankruptcy, or precisely predict the value of the company or the collateral given a default. Ratings are subject to periodic and event-specific surveillance. Factors that could impact our recovery analysis or ratings include:

- Acquisitions and divestitures;
- Updated valuation assumptions;
- Shifts in the profit and cash flow contributions of borrower, guarantor, or non-guarantor entities;
- Changes in debt or the exposure to non-debt liabilities;
- Inter-creditor dynamics; and
- Changes in bankruptcy law.

Features of U.S.-domiciled corporate bankruptcies

Debtor in possession financing. DIP facilities are usually super-priority claims that enjoy repayment precedence over unsecured debt and, in certain circumstances, secured debt. However, it is not possible to accurately quantify the size or likelihood of DIP financing or to forecast how DIP financing may affect the recovery prospects for different creditors. This is because the size or existence of a theoretical DIP commitment is unpredictable, DIP borrowings at emergence may be substantially less than the DIP commitment, and such facilities may be used to fully repay over-collateralized pre-petition secured debt. Further, the presence of DIP financing might actually help creditor recovery prospects by allowing companies to restructure their operations and preserve the value of their business. As a result of these uncertainties, estimating the impact of a DIP facility is beyond the scope of our analysis, even though we recognize that DIP facilities may materially impact recovery prospects in certain cases.

Administrative expenses. Administrative expenses relate to professional fees and other costs associated with bankruptcy that are required to preserve the value of the estate and complete the bankruptcy process. These costs must be paid prior to exiting bankruptcy, making them effectively senior to those of all other creditors. The dollar amount and materiality of administrative claims usually correspond to the complexity of a company's capital structure. We expect that these costs will be less for simple capital structures that can usually negotiate an end to a bankruptcy quickly and may even use a pre-packaged bankruptcy plan. Conversely, these costs are expected to be greater for large borrowers with complex capital structures where the insolvency process is often characterized by protracted multiple party disputes that drive up bankruptcy costs and diminish lender recoveries. When using an enterprise value approach, our methodology estimates the value of these claims as a percentage of the borrower's emergence enterprise value thusly:

- Three percent for capital structures with one primary class of debt;
- Five percent for two primary classes of debt (first-and second-lien creditors may be adversaries in a bankruptcy proceeding and are treated as separate classes for this purpose);
- Seven percent for three primary classes of debt; and
- Ten percent for certain complex capital structures.

When using a discrete asset valuation approach, these costs are implicitly accounted for in the orderly liquidation value discounts used to value a company's assets.

Other nondebt claims

Taxes. Various U.S. government authorities successfully assert tax claims as either administrative, priority, or secured claims. However, it is very difficult to project the level and status of such claims at origination (e.g., tax disputes en route to default are extremely hard to predict). However, their overall amount is seldom material enough to impact lender recoveries, so we generally do not reduce our expectation for lenders' recovery by estimating potential tax claims.

Swap termination costs. The U.S. Bankruptcy Code accords special treatment for counterparties to financial contracts, such as swaps, repurchase agreements, securities contracts, and forward contracts, to ensure continuity in the financial markets and to avoid systemic risk (so long as the type of contract and the type of counterparty fall within certain statutory provisions). Recent amendments to the Bankruptcy Code expanded this safe harbor by, among other things, including within the definition of a "swap" a range of transactions widely used in the capital markets (such as total return swaps and credit swaps) and expanding the definitions of counterparties (whether to swaps, repurchase agreements, securities contracts, or forward contracts) eligible to exercise these rights. In addition to not being subject to the automatic stay that generally precludes creditors from exercising their remedies against the debtor, these financial contract counterparties have the right to liquidate, terminate, or accelerate the contract in a bankruptcy. Most currency and interest rate swaps related to secured debt are secured on a pari passu basis with the respective loans. Other swaps are likely to be unsecured. Quantifying such claims is beyond the scope of our analysis.

Securitizations. Standard accounts receivable securitization programs involve the sale of certain receivables to a bankruptcy-remote special purpose entity in an arms length transaction under commercially reasonable terms. The assets sold are not legally part of the debtor's estate (although in some circumstances they may continue to be reported on the company's balance sheet for accounting purposes), and the securitization investors are completely reliant on the value of the assets they purchased to generate their return. As a result, the securitization investors do not have any recourse against the estate and we do not consider them claimants when we use an enterprise valuation approach in our default and recovery analysis. However, the debtor emerging from bankruptcy will need to finance its trade receivables anew, creating an incremental financing requirement that must be considered in the recovery analysis.

When a discrete asset valuation approach is used, the sold receivables are not available to any creditors. Additionally, future-flow types of securitization, which securitizes all or a portion of the borrower's future revenue and cash flow (typically related to particular contracts, patents, trademarks, or other intangible assets), would effectively reduce all or a part of the enterprise value available to other corporate creditors.

Trade creditor claims. Typically, trade creditor claims are unsecured claims that rank pari passu with a borrower's other unsecured obligations. However, because a borrower's viability as a going concern hinges upon continued access to goods and services, some prepetition claims are either paid in the ordinary course or treated as priority administrative claims. This concession to critical trade vendors ensures that they remain willing to carry on their relationships with the borrower during the insolvency proceedings, thereby preserving the value of the estate and enhancing the recovery prospects for all creditors. Our analysis assumes that these costs continue to be paid as part of the company's normal working capital cycle.

Accordingly, we include trade credit claims as priority obligations only to the extent that we believe there will be valid claims at the time of emergence—or that the company will incur additional debt (including DIP facilities) to pay those claims.

Leases. U.S. bankruptcy law provides companies the opportunity to accept or reject leases during the bankruptcy process. (For commercial real property leases, the review period is limited to 210 days, including a one-time 90-day extension, unless the lessor agrees to an extension.) If a lease is accepted, the company is required to keep rent payments on the lease current, meaning that there will be no claim against the estate. This also allows the lessee to continue to use the leased asset, with the cash flow (i.e., value) derived from the asset available to support other creditors.

If a lease is rejected, the company gives up the use of the asset. (The lessor may file a general unsecured claim against the estate for damages arising from the breach of contract.) We estimate the impact of lease rejection, starting with a lease rejection rate for the firm based on the types of assets leased, the industry, and our simulated default scenario. Leases are typically rejected for one of three reasons:

- The lease is priced above market rates;
- The leased asset is generating negative or insufficient returns; or
- The leased asset is highly vulnerable to obsolescence during the term of the lease.

Our evaluation may ballpark the rejection rate by assuming it matches the percentage decline in revenue in our simulated default scenario or, if applicable, by looking at common industry lease rejection rates. Case-specific considerations might include, for example, that leased assets are unusually old, underutilized, or priced above current market rates; a higher rejection rate in such cases may be warranted.

In bankruptcy, the amount of unsecured claims from rejected leases is determined by taking the amount of lost rental income and subtracting the net value available to the lessor by selling or re-leasing the asset in its next best use. However, the deficiency claims of commercial real estate lessors is further restricted to the greater of one year's rent or 15% of the remaining rental payments, not to exceed three years' rent. Lessors of assets other than commercial real property do not have their potential deficiency claims capped, but such leases are generally not material and are usually for relatively short-periods of time. With these issues in mind, we quantify lease deficiency claims for most companies by multiplying their estimated lease rejection rate by three times their annual rent.

However, there are a few exceptions to our general approach. Deficiency claims for leases of major transportation equipment (e.g., aircraft, railcars, and ships) are specifically analyzed because these lease obligations do not have their claims capped, may be longer term, and are typically for substantial amounts. In addition, we use a lower rent multiple for cases in which a company relies primarily on very short-term leases (three years or less). Further, we do not include any deficiency claim for leases held by individual asset-specific subsidiaries that do not have credit support from other entities (by virtue of guarantees or co-lessee relationships) because of the lack of recourse against other entities and the likelihood that these subsidiaries are likely to be worthless if the leases are rejected. (This situation was relevant in many of the movie exhibitor bankruptcies in the early 2000 time period.)

Employment-related claims. Material unsecured claims may arise when a debtor rejects, terminates, or modifies the terms of employment or benefits for its current or retired employees. To reflect this risk for unsecured debtholders, we are likely to include some level of employment-related claims for companies—but only where uncompetitive labor or benefits costs are a factor in our simulated default scenario.

Pension plan termination claims. The ability to terminate a defined benefit pension plan is provided under the U.S.

Employee Retirement Income Security Act (ERISA). Under ERISA, these plans may be terminated voluntarily by the debtor as the plan sponsor, or involuntarily by the Pension Benefit Guaranty Corporation (PBGC) as the agency that insures plan benefits. Typically, any termination during bankruptcy will be a "distress termination," in which the plan assets would be insufficient to pay benefits under the plan. However, the bankruptcy of the plan sponsor does not automatically result in the termination of its pension plans, and even underfunded plans may not necessarily be terminated; the debtor must demonstrate that it would not be able to successfully reorganize unless the plan is terminated.

In a distress termination, the PBGC assumes the liabilities of the pension plan up to the limits prescribed under ERISA and gets an unsecured claim in bankruptcy against the debtor for the unfunded benefits. The calculation of this liability is based on different assumptions than the borrower's reported liability in its financial statements. This, in addition to the difficulty of predicting the funded status of a plan at some point in the future, complicates our ability to accurately assess the value of these claims. ■

Commercial Paper

Commercial paper (CP) consists of unsecured promissory notes issued to raise short-term funds. CP ratings pertain to the program established to sell such notes. There is no review of individual notes. Typically, only companies of strong credit standing can sell their paper in the money market, although there periodically is some issuance of lesser quality, unrated paper (notably, prior to the junk bond market collapse late in 1989). Alternatively, companies sell commercial paper backed by letters of credit (LOC) from banks. Credit quality of such LOC-backed paper rests entirely on the transaction's legal structure and the bank's creditworthiness. As long as the LOC is structured correctly, credit quality of the direct obligor can be ignored.

Rating Criteria

Evaluation of an issuer's commercial paper reflects our opinion of the issuer's fundamental credit quality. The analytical approach is virtually identical to the one followed in assigning a long-term corporate credit rating, and there is a strong link between the short-term and long-term rating systems. Indeed, the time horizon for CP ratings is not a function of the typical 30-day life of a commercial-paper note, the 270-day maximum maturity for the most common type of commercial paper in the U.S., or even the one-year tenor typically used to determine which instrument gets a short-term rating in the first place.

To achieve an 'A-1+' CP rating, the company's credit quality must be at least the equivalent of an 'A+' long-term corporate credit rating. Similarly, for commercial paper to be rated 'A-1', the long-term corporate credit rating would need to be at least 'A-'. In fact, the 'A+/A-1+' and 'A-/A-1' combinations are rare. Ordinarily, 'A-1' CP ratings are associated with 'A+' and 'A' long-term ratings.

Conversely, knowing the long-term rating will not fully determine a CP rating, considering the overlap in rating categories. However, the range of possibilities is always narrow. To the extent that one of two CP ratings might be assigned at a given level of long-term credit quality (e.g., if the long-term rating is 'A'), overall strength of the credit within the rating category is the main consideration. For example, a marginal 'A' credit likely would have its commercial paper rated 'A-2', whereas a solid 'A' would almost automatically receive an 'A-1'. Exceptional short-term credit quality would be another factor that determines which of two possible CP ratings are assigned. For example, a company may possess substantial liquidity—providing protection in the near or intermediate term—but suffer from less-than-stellar profitability, a longer-term factor. Or, there could be a concern that, over time, the large cash holdings may be used to fund acquisitions. (Having different time horizons as the basis for long- and short-term ratings implies either one or the other rating is expected to change.)

Backup Policies

Ever since the Penn Central bankruptcy roiled the commercial-paper market and some companies found themselves excluded from issuing new commercial paper, we have deemed it prudent for companies that issue commercial paper to make arrangements in advance for alternative sources of liquidity. This alternative, backup liquidity protects companies from defaulting if they are unable to roll over their maturing paper with new notes, because of a shrinkage in the overall commercial-paper market or some cloud over the company that might make commercial paper investors nervous.

Many developments affecting a single company or group of companies—including bad business conditions, a lawsuit, management changes, a rating change—could make commercial-paper investors flee the credit. Given the size of the commercial-paper market, backup facilities could not be relied on with a high degree of confidence in the event of widespread disruption. A general disruption of commercial-paper markets could be a highly volatile scenario, under which most bank lines would represent unreliable claims on whatever cash would be made available through the banking system to support the market. We neither anticipate that such a scenario is likely to develop, nor assume that it never will.

Having inadequate backup liquidity affects both the short-and long-term ratings of the issuer because it could lead to default, which would ultimately pertain to all of the company's debt. Moreover, the need for backup applies to all confidence sensitive obligations, not just rated commercial paper. Backup for 100% of rated commercial paper is meaningless if other debt maturities—for which there is no backup—coincide with those of the commercial paper. Thus, the scope of backup must extend to euro-denominated commercial paper, master notes, and short-term bank notes.

The standard for industrial and utility issuers has long been 100% coverage of confidence-sensitive paper for all but the strongest credits. Companies rated 'A-1+' can provide 50%-75% coverage. A higher-rated entity is less likely to encounter business reverses of significance and—in the event of a general contraction of the commercial-paper market—the higher-rated credit would be less likely to lose investors. In fact, higher-rated companies could actually be net beneficiaries of a flight to quality.

While the backup requirement relates only to outstanding paper—rather than the entire program authorization—a company should anticipate prospective needs. For example, it may have upcoming maturities of long-term debt that it may want to refinance with commercial paper, which would then call for backup of greater amounts.

Available cash or marketable securities are ideal to provide backup. (Of course, it may be necessary to "haircut" their apparent value to account for potential fluctuation in value or tollgate taxes surrounding a sale. And it is critical that they be immediately saleable.) Yet the vast majority of commercial paper issuers rely on bank facilities for alternative liquidity.

The high standard for back-up liquidity has provided a sense of security to the commercial paper market—even though backup facilities are far from a guarantee that liquidity will, in the end, be available. For example, a company could be denied funds if its banks invoked material adverse change clauses. Alternatively, a company in trouble might draw down its credit line to fund other cash needs, leaving less-than full coverage of paper outstanding, or issue paper beyond the expiration date of its lines.

In 1999, we introduced a new approach that offers companies greater flexibility regarding the amount of backup they maintain, if they are prepared to match their maturities carefully with available liquidity. The alternative approach differentiated between companies that are rolling over all their commercial paper in just a few days and those that have a cushion by virtue of having placed longer-dated paper. The basic idea was that companies—if and when they lose access to commercial paper—should have sufficient liquidity to cover any paper coming due during the time they would require to arrange additional funding. However, companies encountered practical difficulties in implementing the new approach. Moreover, changes in the banking environment have since made us more leery about a company arranging new facilities when under stress.

Still, notes that come due only 11-12 months from now do not require backup so far in advance. Companies should begin to actively arrange liquidity backup approximately six months prior to maturity. Similarly, 12-month notes that automatically extend their maturity month by month do not require back-up arrangements from day one. They will be able to arrange backup when and if the extensions stop, leaving a full 12 months to do so.

Extendible commercial notes (ECNs) provide built-in backup by allowing the issuer to extend for several months if there is difficulty in rolling over the notes; accordingly, there is no need to provide backup for them—i.e., until the extension is effected. However, there is no way to prevent the issuer from tapping backup facilities intended for other debt and use the funds to repay maturing ECNs, instead of extending. This risk is known as leakage. Accordingly, for issuers that provide 100% backup, unbacked ECNs must not exceed 20% of extant backup for outstanding conventional commercial paper.

All issuers—even if they provide 100% backup—must always ensure that the first few days of upcoming maturities are backed with excess cash or funding facilities that provide for immediate availability. For example, a bank backup facility that requires two-day notification to draw down will be of no use in repaying paper maturing in the interim. The same would hold true if foreign exchange is needed, and the facility requires a few days to provide it. Moreover, if a company issuing commercial paper in the U.S. were relying on a bank facility in Europe, differences in time zones or bank holidays could prevent availability when needed. Obviously, a bank facility in the U.S. would be equally lacking with respect to maturing euro-denominated commercial paper. So-called swing lines typically equal 15%-20% of the program size to deal with the maximum amount that will mature in any three-to four-day period.

Quality Of Backup Facilities

Banks offer various types of credit facilities that differ widely regarding the degree of the bank's commitment to advance cash under all circumstances. Weaker forms of commitment, while less costly to issuers, provide banks great flexibility to redirect credit at their own discretion. Some lines are little more than an invitation to do business at some future date.

We expect all backup lines to be in place and confirmed in writing. Pre-approved lines or orally committed lines are viewed as insufficient. Specific designation for commercial-paper backup is of little significance.

Contractually committed facilities are desirable. In the U.S., fully documented revolving credits represent such contractual commitments. The weaker the credit the greater the need for more reliable forms of liquidity. As a general guideline, if contractually committed facilities cover 10-15 days' upcoming maturities of outstanding paper, that should suffice.

Even contractual commitments often include "material adverse change" clauses, allowing the bank to withdraw under certain circumstances. While inclusion of such an escape clause weakens the commitment, we do not consider it critical—or realistic—for most borrowers to negotiate removal of "material adverse change" clauses.

In the absence of a contractual commitment, payment for the facility—whether by fee or balances—is important because it generally creates some degree of moral commitment on the part of the bank. In fact, a solid business relationship is key to whether a bank will stand by its client. Standardized criteria cannot capture or assess the strength of such relationships. We therefore are interested in any evidence—subjective as it may be—that might demonstrate the strength of an issuer's banking relationships. In this respect, the analyst is also mindful of the business cultures in different parts of the world and their impact on banking relationships and commitments.

Dependence on just one or a few banks also is viewed as an unwarranted risk. Apart from the potential that the bank will not have adequate capacity to lend, there is the chance it will not be willing to lend to this issuer. Having several banking relationships diversifies the risk that any bank will lose confidence in this borrower and hesitate to provide funds.

Concentration of banking facilities also tends to increase the dollar amount of an individual bank's participation. As the dollar amount of the exposure becomes large, the bank may be more reluctant to step up to its commitment. In addition, the potential requirement of higher-level authorizations at the bank could create logistical problems with respect to expeditious access to funds for the issuer. On the other hand, a company will not benefit if it spreads its banking business so thinly that it lacks a substantial relationship with any of its banks.

There is no analytical distinction to be made between a 364-day and a 365-day facility. Even multiyear facilities will provide commitment for only a short time as they approach the end of their terms. It obviously is critical that the company arranges for the continuation of its banking facilities well in advance of their lapsing.

It is important to reiterate that even the strongest form of backup—a revolver with no "material adverse change" clause—does not enhance the underlying credit and does not lead to a higher rating than indicated by the company's own creditworthiness. Credit enhancement can be accomplished only through an LOC or another instrument that unconditionally transfers the debt obligation to a higher-rated entity.

Banks providing issuers with facilities for backup liquidity should themselves be sound. Possession of an investment-grade rating indicates sufficient financial strength for the purpose of providing a commercial paper issuer with a reliable source of funding.

There is no requirement that the bank's credit rating equal the CP issuer's rating; nonetheless, we look askance at situations where most of a company's banks were only marginally investment grade. That would indicate an imprudent reliance on banks that might deteriorate to weaker, noninvestment-grade status. ■

Docket No. E-01345A-08-0172
Schedule A
Page 1 of 1

Arizona Public Service Company
Computation of Increase in Gross Revenue Requirement
On Change in Rate Base Since Decision 69663
ACC Jurisdictional

Test Year Ended December 31, 2007

Line No.	Description	Reference	Original Cost (A)
1	Adjusted Rate Base	Sch. B	$ 537,987
2	Rate of Return	Sch. D	8.32%
3	Operating Income Required		$ 44,753
4	Net Operating Income Available	Sch. C	$ 5,212 [a]
5	Operating Income Excess/Deficiency		$ 39,541
6	Gross Revenue Conversion Factor	Sch. A-1	1.6491
7	Base Rate Revenue Increase for Interim Rates		$ 65,206

Notes and Source
[a] Interest synchronization

Arizona Public Service Company
Computation of Gross Revenue Conversion Factor
For Alternative Interim Rates

Docket No. E-01345A-08-0172
Schedule A-1
Page 1 of 1

Test Year Ended December 31, 2007

Line No.	Description		Company Proposed (A)
1	Gross Revenue		100.00%
2	Less: State income taxes		6.71000%
3	Taxable Income as a Percent		93.29%
4	Less: Federal and State Income Taxes	35%	32.65%
5	Change in Net Operating Income		60.64%
6	Gross Revenue Conversion Factor		1.6491

Notes and Source

APS Amended Application, Schedule C-3

Components of Interim Revenue Requirement Increase $ 65,206 Sch A

		Percent	Amount
7	Net Income	60.64%	$ 39,541
8	Federal and State Income Taxes	39.36%	$ 25,665
9	Uncollectibles		$ -
10	Total Revenue Increase	100.00%	$ 65,206

Arizona Public Service Company
Summary of Rate Base Change
From Decision No. 69663 to Unadjusted Test Year Ended 12/31/07

Docket No. E-01345A-08-0172
Schedule B
Page 1 of 1

(Thousands of Dollars)

Line No.	Capital Source	Last Case E-01345A-05-0816 (A)	Current Case E-01345A-08-0172 (B)	Difference (C)
1	Original Cost Rate Base	$ 4,403,496	$ 4,941,483	$ 537,987

Notes and Source
Decision No. 69663, page 15
APS Amended Application, Schedule B-1, page 1, Column D, ACC Jurisdiction, Unadjusted Test Year ended 12/31/2007

Arizona Public Service Company
Interest Synchronization

Docket No. E-01345A-08-0172
Schedule C
Page 1 of 1

Test Year Ended December 31, 2007
(Thousands of Dollars)

Line No.	Description	ACC Jurisdictional Amount (A)	Reference
1	Change in jurisdictional rate base	$ 537,987	Schedule B
2	Weighted cost of debt	2.46%	Schedule D
3	Synchronized interest deduction	$ 13,243	Line 1 x Line 2
4	Synchronized interest deduction	$ -	Note A
5	Difference (decreased) increased interest deduction	$ 13,243	Line 3 - Line 4
6	Combined federal and state income tax rates	39.360%	Note B
7	Increase (decrease) to income tax expense	$ (5,212)	
8	Increase (decrease) to net operating income	$ 5,212	

Notes and Source

A None on the difference in jurisdictional rate base from Decision No. 69663

B APS Amended Application, Schedule C-2

Arizona Public Service Company
Capital Structure & Cost Rates
For Alternative Interim Rates

Docket No. E-01345A-05-0816
Schedule D
Page 1 of 1

Last Authorized Cost of Capital

Line No.	Capital Source	Capitalization Amount	Capitalization Percent	Cost Rate	Weighted Avg. Cost of Capital
1	Short-Term Debt			5.92%	0.00%
2	Long-Term Debt		45.50%	5.41%	2.46%
3	Common Stock Equity		54.50%	10.75%	5.86%
4	Total Capital	$ -	100.00%		8.32%

Notes and Source
Decision No. 69663, page 49

EXHIBIT S-2

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01345A-08-0172

DIRECT

TESTIMONY

OF

DAVID C. PARCELL

ON BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

AUGUST 29, 2008

TABLE OF CONTENTS

SCHEDULES

ATTACHMENTS

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is Suite 601, 1051 East Cary Street, Richmond, Virginia 23219.

Q. Please summarize your educational background and professional experience.

A. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia Commonwealth University. I have been a consulting economist with Technical Associates since 1970. I have provided cost of capital testimony in public utility ratemaking proceedings dating back to 1972. In connection with this, I have previously filed testimony and/or testified in over 400 utility proceedings before 40 regulatory agencies in the United States and Canada. Attachment 1 provides a more complete description of my education and relevant work experience.

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes, I have testified in a number of prior Arizona Corporation Commission ("Commission") utility rate proceedings, including the recent electric rate cases involving Arizona Public Service Company (Docket No. E-01345A-05-0816), UNS Gas, Inc. (Docket No. G-01345A-05-0463), UNS Electric, Inc. (Docket No. E-0404A-06-0783), Tucson Electric Power Co. (Docket No. E-01933A-07-0402) and Southwest Gas Company (Docket No. G-01551A-07-0504). Those testimonies were provided on behalf of the Utilities Division Staff.

Q. What is the purpose of your testimony?

A. My testimony addresses the financial and cost of capital implications of Arizona Public Service Company's ("APS" or "Company") Motion for Approval of Interim Rate and Preliminary Order. My testimony is designed to provide the Commission with additional information on whether the Company's apparent nexus between a singular rating agency financial metric and its Interim Rate request is compelling.

Q. What is your understanding of the basis for APS' Interim Rate Request?

A. The position of APS is contained in the affidavit of Donald E. Brandt. On page 4, lines 7-12, Mr. Brandt makes the following statement:

> *I believe that, without interim relief of the type requested in the Company's Motion, it is more than likely that APS will be downgraded to junk status before the Commission issues a decision in the Company's general rate proceeding, resulting in approximately one billion dollars of additional costs over the next ten years that will ultimately be borne by APS customers.*

A primary aspect of the Company's request for Interim Rates is based on APS' belief that there is a likelihood of a downgrading of its securities in the absence of Interim Rates. This downgrade possibility, in turn, is primarily based upon the Company's focus on the Standard & Poor's ("S&P") financial ratio Funds from Operations to Debt ratio ("FFO/Debt"). This is demonstrated in Mr. Brandt's affidavit on page 12, lines 5-9, where he makes the following statement:

> *The rating agencies have established financial metrics as guidelines for determining a credit rating. The key financial metric examined by the credit rating agencies is the FFO/Debt ratio, which measures the sufficiency of a company's cash flow to service both debt interest and debt principal over time.*

Mr. Brandt goes on to state (page 12, lines 14-16) that APS' FFO/Debt ratio will fall below the 18 percent "threshold" by the end of 2009. Based on this, he concludes that a downgrade will occur in the absence of the approval of Interim Rates.

Q. What is your conclusion concerning the necessity for Interim Rates in terms of APS' rationale for requesting such rates?

A. I conclude that APS' focus on a single financial metric (FFO/Debt) is not representative of the manner in which the respective rating agencies indicate that ratings are established. It is evident that many factors go into the ratings process.

It is also evident that APS has the lowest investment grade rating with only one of the three major rating agencies (S&P). The other two agencies (Moody's and Fitch) rate APS two grades above the investment grade category. Further, all these rating agencies give APS a "stable" outlook. Based upon these factors, I do not believe that APS is presently at any significant risk of a downgrade.

RATING AGENCY METHODOLOGIES

Q. How do the rating agencies define individual ratings?

A. Each of the three rating agencies has established a series of rating categories with which to rate corporate securities. These are shown below:

Fitch	Moody's	S&P
AAA	Aaa	AAA
AA+	Aa1	AA+
AA	Aa2	AA
AA-	Aa3	AA-
A+	A1	A+
A	A2	A
A-	A3	A-
BBB+	Baa1	BBB+
BBB	Baa2	BBB
BBB-	Baa3	BBB-
BB+	Ba1	BB+
BB	Ba2	BB
BB-	Ba3	BB-
B+	B1	B+
B	B2	B
B-	B3	B-
CCC+	Caa1	CCC+

Note that there are several categories of CCC and below that are not shown above.

It is universally accepted that "investment grade" is defined as a rating of triple-B or above. Moody's, for example, defines "investment grade" as "issuers rated from Aaa to Baa globally" on its website (Attachment 2). Ratings of less than triple-B are referred to as non-investment grade, or sometimes referred to as "junk bond" status. The Moody's scale, for example, provides the following description of its rating categories[1]:

Aaa	"high grade"
Aa	"high grade"
A	"upper-medium grade"
Baa	"medium grade"
Ba	"speculative elements"
B	"lack characteristics of the desirable investment"
Caa	"poor standing"
Ca	"speculative in high degree"
C	"lowest rated class"

[1] Source: Mergent Bond Record (Attachment 3).

Q. Do the rating agencies provide any additional indications of possible trends in a company's ratings?

A. Yes, they do. Each of the rating agencies employs a set of four "outlook" indicators – negative, stable, positive, and under review. These are intended to provide an indication of the potential direction of any possible ratings change.

Q. How do the rating agencies determine the security ratings that are assigned to corporations such as public utilities?

A. The rating agencies utilize a number of quantitative and qualitative factors in assigning security ratings. S&P is more commonly cited in this regard since this rating agency provides more direct indications as to how its ratings are determined.

In providing ratings for public utilities, S&P utilizes a "Business Risk Profile" and a "Financial Risk Profile." These are described in a November 30, 2007 RatingsDirect (Attachment 4). The Business Risk Profile contains five categories:

Excellent
Strong
Satisfactory
Weak
Vulnerable

The Financial Risk Profile, in turn, contains five categories:

Minimal
Modest
Intermediate
Aggressive
Highly leveraged

Q. What factors does S&P utilize in establishing a Business Risk Profile for a public utility?

A. S&P indicates that it uses the following factors to establish a Business Risk Profile:

> Regulation
> Markets
> Operations
> Competitiveness, and
> Management

Q. How does S&P indicate that it applies Financial Risk Profiles for public utilities?

A. S&P indicates the following: "Financial risk is analyzed both qualitatively and quantitatively, mainly with financial ratios and other metrics that are calculated after various analytical adjustments are performed on financial statements prepared under GAAP."

S&P identifies the following three financial ratios as the quantitative basis for its ratings:

> FFO/Debt (%),
> FFO/Interest (x), and
> Total debt/capital (%)

Q. Does S&P indicate if it uses these guidelines exclusively in establishing ratings?

A. S&P indicates that it does not use these financial guidelines exclusively in setting ratings. In the November 30, 2007 RatingsDirect, S&P noted:

> *Note that even after we assign a company a business risk and financial risk, the committee does not arrive by rote at a rating based on the matrix. The matrix is a guide—it is not intended to convey precision in the ratings process or reduce the decision to plotting intersections on a graph. Many small positives and negatives that affect credit quality can lead a committee to a different conclusion than what is indicated in the matrix.*

Q. Do the other rating agencies also consider multiple factors in establishing security ratings?

A. Yes, they do. Fitch, for example, describes its ratings methodology in a July 31, 2007 publication titled "Credit Rating Guidelines For Regulated Utility Companies" (Attachment 5). In this, Fitch stated:

> *These guidelines are an overview of Fitch Ratings' global approach to credit ratings for electric, natural gas and water utilities.*
>
> . . .
>
> *The rating evaluation of an electric, gas or water utility considers the qualitative and quantitative risks associated with the company's business and corporate structure in combination with the company's financial strength and liquidity. The financial assessment emphasizes cash flow financial measures rather than equity or earnings-based ratios. The analytical focus is on the adequacy of the utility's cash flow relative to fixed charges, debt obligations and capital expenditures as well as its capital structure, liquidity and profitability.*
>
> *The assessment of operating and business risks is an important element in determining ratings. This analysis is carried out using both quantitative and qualitative methods. Quantitative factors with the most significant effect on companies in the utilities sector include an evaluation of the regulatory and political environment in which the utility operates, including such factors as price-setting and cost-recovery mechanisms, transparency and predictability of the regulatory regime, exposure to competition and the nature of the customer franchise. In addition, Fitch's operational and business evaluation considers the degree of which the utility bears financial exposure to variations in commodity costs and in the case of network businesses, the responsibility for reliable supply. The business risk profile is also influenced by factors such as customer demographics, the type and quality of assets, operating performance, fuel mix, exposure to hydrological risk and management's strategy and capability. Each of these factors will affect the predictability or volatility of a utility's cash flow.*
>
> *The assessment of operating risk also includes a review of the historical volatility of operating cash flow, when available, compared to the historical trend of similar companies. Fitch analysts review past cash flow trends to assess how the volatility or stability has been affected by the*

> *aforementioned fundamental factors. The assessment incorporates analytical judgment about how fundamental factors may affect the company's future operating cash flow.*

Fitch identifies the following factors that it considers:

Corporate/Legal Structure
Regulatory Environment
Franchise or Concession Terms
Price Setting
Potential For Regulatory Change
Service Area Demographics
Energy Supply
Commodity Price Exposure
Operating Efficiency
Management and Strategy
Financial Resources
Capital Structure and Financial Flexibility
Financial Ratio Analysis
Liquidity
Risk Assessment and Guideline Credit Ratios

It is obvious from this Fitch report that a larger number of factors are considered in establishing credit ratings. Clearly, Fitch does not focus on a single ratio in setting ratings.

Q. Does Moody's also utilize multiple criteria in establishing ratings for utilities?

A. Yes, it does. Unlike S&P and Fitch, however, Moody's does not appear to be as definitive in its rating review methodology. Nevertheless, it is evident from a July 28, 2008 Credit Opinion on APS (Attachment 6) that Moody's considers a number of both qualitative and quantitative factors including:

Stability of regulated cash flows;
Economic strength of service territory;
Regulatory environment; and,

Cash flow metrics.

Moody's cites four cash flow metrics:

CFO pre-W/C to Interest (x);
CFO pre-W/C to Debt (%);
CFO pre-W/C – Dividends to Debt (%); and,
Total Debt to Book Capitalization.

This indicates that Moody's also considers multiple factors in setting its rating.

APS RATING STATUS

Q. What are the current bond ratings of APS?

A. There are three major bond rating agencies in the U. S. The current ratings of APS are as follows:

	Issuer Rating	Senior Unsecured
Fitch	BBB	BBB
Moody's	Baa2	Baa2
S&P	BBB-	BBB-

Each of these fall in the "investment grade" category, which is Triple B- or above.

Q. How do these ratings compare to other electric utilities?

A. According to AUS Utility Reports (Attachment 7), the Moody's and S&P ratings for the electric utilities they cover are as follows:

Rating	Moody's	S&P
Aaa/AAA	1	--
Aa2/AA	2	1
Aa3/AA-	1	--
A1/A+	6	3
A2/A	5	6
A3/A-	10	7
Baa1/BBB+	15	16
Baa2/BBB	**13**	15
Baa3/BBB-	5	**8**
Ba1/BB+	2	3
B2	1	--
Not Rated	4	4

Source: AUS Utility Reports, July 2007.

Note: The bold numbers reflect APS' current ratings.

This indicates that Pinnacle West Capital (APS) has bond ratings somewhat less than other electric utilities, but still within investment grade status.

Q. What are the current outlooks for APS?

A. The current outlooks for APS are as follows:

Fitch	Stable
Moody's	Stable
S&P	Stable

Q. What is the most recent change in the respective outlooks for APS?

A. The most recent change in outlook was favorable as follows:

Moody's	Negative to Stable	July 25, 2008

Q. Why did Moody's revise APS' outlook from negative to stable?

A. This revision was noted in a July 25, 2008 Moody's Global Credit Research Rating Action (Attachment 8). In announcing the upgrade in outlook, Moody's noted the following:

> *Moody's Investors Service changed the rating outlooks of Pinnacle West Capital Corporation (Pinnacle, Baa3 senior unsecured) and its subsidiaries, Arizona Public Service Company (APS, Baa2 senior unsecured) and VNGS II Funding Corp. Inc. (PVNGS: Baa2, senior secured lease obligation bonds) to stable from negative.*
>
> *The stable outlook considers the companies' improving regulatory environment and operating performance with financial results that are expected to remain consistently within the range expected for integrated utilities rated Baa. APS has begun to receive more supportive regulatory decisions, including "new connection" fees allowing faster recovery for new hookups plus a transmission cost adjustor and power supply adjustor which has limited APS' exposure to fuel and purchased power fluctuations. In addition, performance at the Palo Verde nuclear power plant has improved and APS is making progress in identifying and improving the safety and communication issues at the plant.*
>
> *As a result of some improved timing on cost recoveries, Moody's now expects APS and Pinnacle's cash flow credit metrics to remain at levels comparable to those achieved in 2006 and 2007. This would place the utility and parent in the mid-to-upper range of ratios for electric utilities with medium business risk according to Moody's rating methodology for global regulated electric utilities.*

Q. Has S&P commented on APS in any recent reports?

A. Yes, it has. In a June 25, 2008 RatingsDirect (Attachment 9), S&P affirmed APS' BBB- corporate credit rating and also affirmed the Stable outlook. In affirming these factors, S&P did acknowledge that "APS continued to face significant regulatory challenges."

S&P's Stable outlook for APS was described as follows:

> *The stable outlook reflects our expectation that consolidated cash flow volatility has been tamped down by the ACC's approval of a stronger PSA that speeds the recovery of fuel costs, but consolidated financial performance will continue to be challenged by regulatory lag at APS, which could be moderated by APS' pending interim rate request. The stable outlook is premised on no meaningful adverse changes in the company's business risks and continued financial performance that is not significantly weaker than 2007 results. Equity issuances will be expected to balance the capital structure of the company as APS continues to invest heavily in infrastructure. Ratings could be lowered to speculative grade if the company is not able to overcome the challenge of ensuring timely recovery of its prudently incurred costs through rate increases approved by the ACC. Given these challenges, and that presented by NRC scrutiny of Palo Verde, we see little potential for positive movement in the ratings or outlook.*

This quote does indicate S&P's concerns with APS' challenges. On the other hand, S&P cites recent Commission approval of a stronger PSA that speeds recovery of fuel costs. Notably, even though it cited the Interim Rates filing, S&P did not express any prediction of a downgrade of APS in the absence of Interim Rates being approved. I also note that APS' stable outlook reflects these factors

Q. How should the S&P financial ratios, as cited above, apply to APS?

A. According to a June 2, 2008 publication by S&P titled "Issuer Ranking" U.S. Regulated Electric Utilities, Strongest to Weakest" (Attachment 10) APS has the following profiles:

Business Profile	Strong
Financial Profile	Aggressive

Based on these respective profiles, S&P indicates, in a November 30, 2007 RatingsDirect (Attachment 4), the following "guidelines" for a utility with APS' financial risk profile:

FFO/debt	10% - 30%
FFO/interest	2.0x – 3.5x
Total debt/capital	45% - 60%

Q. Mr. Brandt states, on page 12, lines 6-8, of his affidavit that "the key financial metric examined by the credit rating agencies is the FFO/Debt ratio of 18% to 28%." Does this statement conform to your review of S&P and other rating agency reports and stated criteria?

A. No, it does not. As I have shown above, the rating agencies use a number of criteria, both quantitative and qualitative, in determining ratings. I have seen no indications that either S&P or any other rating agency place primary reliance on any single financial metric in setting ratings.

Q. Are there any other factors that may impact the financial metrics of APS?

A. Yes. The Commission recently approved an application of Pinnacle West Capital to sell up to $400 million of new equity and infuse this into APS. The addition of $400 million of new equity into APS should have the impact of improving the FFO/Debt ratio of the company, as well as the total debt/total capital metric. I note that this financing was approved by the Commission on August 6, 2008, or after the date of Mr. Brandt's affidavit (June 6, 2008). As a result, any impact of the infusion on APS' financial metrics is not included in Mr. Brandt's affidavit.

A demonstration of the positive impact of an equity infusion is provided in the response to Data Request Staff Interim 2.26 (Attachment 11). This response indicates that a prior equity infusion of $460 million in 2005 and 2006 had the impact of raising the FFO/Debt ratio of the Company.

PINNACLE WEST CAPITAL STOCK RANKINGS

Q. Are there other indicators of financial strength and viability that can be used to compare electric utilities?

A. Yes, there are. These include:

Value Line Safety[2]	(Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk)
Value Line Beta[2]	(Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.)
Value Line Financial Strength[2]	(Financial strengths range from C to A++, with the latter representing the highest level.)
Standard & Poor's Stock Ranking[3]	(Common stock rankings range from D to A+, with the latter representing the highest level.)

Each of these indicators can be used to compare various companies, including electric utilities such as Pinnacle West Capital, with other companies.

Q. What are the respective financial indicators of Pinnacle West Capital and the electric utility industry?

A. Pinnacle West Capital's indicators (Attachment 14) and the averages for the electric utility industry are currently as follows:

---

2 Source: Attachment 12.

3 Source: Attachment 13.

	PWC	Elec. Util.
Value Line Safety	2	2.3
Value Line Beta	.80	.87
Value Line Financial Strength	A	
S&P Stock Ranking	B+	

Q. How do these compare to other electric utilities?

A. This comparison is shown on Schedule 1 of Exhibit___(DCP-1). This reveals the following comparisons:

Value Line Safety – Pinnacle West Capital's 2 (on a scale of 1 to 5 with 1 being the highest level of Safety – note that Pinnacle West has a Safety of 1 until August 8, 2008) falls in the upper middle range of electric utilities. Schedule 1 indicates that virtually all of the electric utilities have a Safety of 1, 2 or 3, with an average of 2.3. The number of companies with each rating is:

1	8
2	27
3	23
4	--
5	1

This is reflective of slightly below-average risk for Pinnacle West Capital.

Value Line Beta – Pinnacle West Capital's .80 beta is slightly less than the electric industry average beta of .87. This is also indicative of slightly less risk.

Value Line Financial Strength – Pinnacle West Capital's Financial Strength is A, which is slightly above average for the electric industry. The number of companies with each rating is:

A+	3
A	18
B++	17
B+	10
B	8
C++	1
C+	--
C	1

This reflects below-average risk of Pinnacle West Capital.

S&P Stock Ranking – Pinnacle West Capital's B+ ranking is above the average of the electric utility industry. The number of companies with each ranking is:

A	1
A-	9
B+	14
B	28
B-	--
C	2

This also reflects below-average risk of Pinnacle West Capital.

Collectively, these indicators portray Pinnacle West Capital as a below-risk electric utility holding company.

CONCLUSION

Q. Please summarize your testimony and conclusions.

A. The affidavit of APS witness Brandt reflects the Company's position that Interim Rates are necessary in order to avoid a ratings downgrade to non-investment grade status. The Company's prediction of ratings downgrades, in turn, is based on the claim that a single financial metric (FFO/Debt) is the primary factor used by the rating agencies in assigning ratings to individual companies such as APS.

My testimony provides a more comprehensive assessment of what the rating agencies indicate, in their published reports, the methodologies and factors that are considered in the ratings process. It is apparent, based on the rating agencies' published reports, that a large number of factors are considered in assigning ratings. These include both qualitative and quantitative factors. There is no indication that a single financial metric, such as FFO/Debt, is a primary determinant in the rating process.

My testimony also indicates that APS has ratings by Fitch and Moody's of "middle B" (BBB by Fitch and Baa2 by Moody's), which are two "notches" above the non-investment grade status. S&P's ratings are BBB-, which is a single "notch" above non-investment grade status. All three rating agencies have "outlooks" for APS of "Stable". A typical company in danger of being downgraded would be expected to have an Outlook of either "Negative" or "Under Review." This information does not provide any significant indication of a danger of APS being downgraded to non-investment grade status.

The stock rankings of APS' parent – Pinnacle West Capital – are typically in the above-average categories for electric utilities. This is indicative of below-average risk for APS and Pinnacle West Capital.

Based upon these analyses, it is my conclusion that the rationale provided by APS in support of its request for Interim Rates is not persuasive and does not provide a proper justification for Interim Rates based on a need to maintain investment grade ratings.

Q. Does this conclude your pre-filed testimony?

A. Yes, it does.

Exhibit___(DCP-1)
Schedule 1

ELECTRIC UTILITIES FOLLOWED BY VALUE LINE INVESTMENT SURVEY
COMPARISON OF FINANICAL INDICATORS

COMPANY	ELECTRIC SUB	EQUITY RATIO Value Line	VALUE LINE SAFETY	BETA	FIN STR	S&P STOCK RANKING S&P	S&P BOND RATING AUS	MOODY'S BOND RATING AUS
ALLETE	Minnesota Power	64.4%	2	0.95	A	B+	A-	Baa1
Alliant Energy	WPL, IES & ISP	61.9%	2	0.80	A	B	A-	A2
Allegheny Energy		39.0%	3	1.15	B++	B	BBB+	Baa2
Ameren Corp.	Un El & CIPSCO	53.4%	2	0.80	A	A-	BBB	Baa2
American Electric Power Company	AEP & C&SW	41.2%	3	0.85	B++	B	BBB	Baa1
Aquila, Inc.	UtiliCorp	56.7%	5	1.35	C	C	B+	Ba3
Avista Corp.	Wash Water Pwr	59.0%	3	0.95	B+	B	BBB+	Baa2
Black Hills Corp.	Black Hills Power	63.2%	3	0.90	B+	B	BBB	Baa1
CMS Energy Corp.	Consumers Energy	25.9%	3	1.15	B	C	BBB	Baa1
CH Energy Group, Inc.	Cen Hud G & E	55.2%	1	0.90	A	A-	A	A2
CenterPoint Energy, Inc.	Houston Electric	17.8%	3	0.95	B	B	NR	Baa2
Central Vermont Public Service Corp		60.6%	3	1.10	B	B+	BBB+	NR
Cleco Corp.	Cen La Elec	57.0%	3	1.00	B+	B+	BBB	A3
Consolidated Edison, Inc.		53.1%	1	0.75	A++	B+	A	A1
Constellation Energy Group	Baltimore Gas & Elec	52.4%	2	0.90	A	B+	BBB+	Baa2
DPL, Inc.	Dayton P&L	35.8%	3	0.75	B	B+	A-	A2
Dominion Resources	VA Power	41.1%	2	0.80	B++	B+	A-	Baa1
DTE Energy Company	Detroit Edison	45.6%	3	0.75	B+	B	A-	A3
Duke Energy Corp.		69.1%	2	NMF	A	B	A	A3
Edison International	So. Cal Edison	46.0%	3	0.85	B++	B	A	A2
El Paso Electric Co.		50.4%	2	0.90	B++	B	BBB	Baa2
Empire District Electric Company		49.9%	3	0.85	B+	B	BBB+	Baa1
Energy East Corp.	NYSEG, RG&E, CMP	45.1%	2	0.75	B++	B+	A-	A3
Entergy Corp.		43.9%	2	0.85	A	A-	A-	Baa2
Exelon Corp.	PECO & Comm Ed	45.7%	1	0.85	A+	B+	A-	A3
FPL Group, Inc.	Florida P & L	48.8%	1	0.80	A+	A-	A	Aa3
FirstEnergy Corp.	OhEd,CIE,Tol,MeEd,JC	50.3%	2	0.80	A	A-	BBB	Baa2
Great Plains Energy Inc.	KCP&L	57.9%	2	0.75	A	B	BBB	A3
Hawaiian Electric Industries, Inc.	Hawaiian Elec. Co.	51.0%	2	0.70	B++	B	BBB	Baa2
IDACORP	Idaho Power	51.1%	3	0.90	B+	B	A-	A3
Integrys Energy Group	Wisconsin Pub Ser	58.3%	2	0.80	B++	A-	A-	A1
ITC Holdings Corp.			3	0.85	B	NR		
MDU Resources Group	Montana Dak Util	68.4%	1	0.95	A+	A	BBB+	A2
MGE Energy Inc.	Madison Gas & Elec	64.8%	1	0.90	A	B+	AA-	Aa2
NiSource Inc.	NIPSCO	47.6%	3	0.90	B+	B	BBB-	Baa2
Northeast Utilities	NU sys	48.8%	3	0.75	B+	B	BBB+	Baa1
NSTAR	NSTAR Elec.	40.1%	1	0.80	A	A-	AA-	A1
OGE Energy Corp.	Okla Gas & Elec	55.6%	2	0.80	A	A-	BBB+	Baa2
Otter Tail Corp	Otter Tail Power	59.4%	2	0.90	A	A-	BBB+	A3
PG&E Corp.	Pacific G & E	50.4%	2	0.80	B++	B	BBB+	A3
PPL Corp	PPL Utilities	43.6%	2	0.90	B++	B+	A-	A3
Pinnacle West Capital Corp.	Ariz Pub Ser	53.0%	2	0.80	A	B+	BBB-	Baa2
Pepco Holdings, Inc.	Pepco & Conectiv	45.9%	3	0.90	B	B	BBB+	Baa1
Portland General		46.5%	2	0.85	B++	NR	A	Baa1
Progress Energy	CP&L & Fl Prog	48.8%	2	0.80	B++	B	A-	A2
Public Service Enterprise Group, Inc.	PSE&G	45.5%	3	0.90	B++	B+	A-	A3
PNM Resources	P S of New Mexico	57.6%	3	0.85	B+	B	BBB-	Baa2
Puget Energy, Inc.	Puget Sound Energy	48.5%	3	0.80	B+	B	BBB+	Baa2
SCANA Corp.	SCE&G	49.7%	2	0.85	A	B	A-	A2
Sempra Energy	San Diego G & E	63.7%	2	0.90	A	B+	A+	A1
Sierra Pacific Resources	Nev Pwr & SP Pwr	42.0%	3	1.05	B	B	BB+	Baa3
Southern Company	GA Pwr, Ala Pwr, M Pw	44.9%	1	0.70	A	A-	A	A2
TECO Energy, Inc.	Tampa Elec	39.0%	3	0.95	B	B	BBB-	Baa2
UniSource Energy Corp.	Tucson Electric Power	31.2%	3	0.60	C++	B	BBB	Baa2
UIL Holdings	United Illum	49.2%	2	0.90	B++	B	NR	Baa2
Vectren	Ind Ener & SIGCORP	49.8%	2	0.90	A	B+	A	A3
Westar Energy, Inc.	KP&L	48.9%	2	0.85	B++	B	BBB-	Baa2
Wisconsin Energy Corp.	We Energies	49.2%	2	0.80	B++	B	A-	Aa3
Xcel Energy Inc.	N S Pwr, PSC, SWPS	49.4%	2	0.75	B++	B	A-	A3
Average		**49.9%**	**2.31**	**0.87**				

Sources: Value Line and Standard & Poor's Stock Guide.

BACKGROUND AND EXPERIENCE PROFILE
DAVID C. PARCELL, MBA, CRRA
PRESIDENT/SENIOR ECONOMIST

EDUCATION

1985	M.B.A., Virginia Commonwealth University
1970	M.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)
1969	B.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)

POSITIONS

2007-Present	President, Technical Associates, Inc.
1995-2007	Executive Vice President and Senior Economist, Technical Associates, Inc.
1993-1995	Vice President and Senior Economist, C. W. Amos of Virginia
1972-1993	Vice President and Senior Economist, Technical Associates, Inc.
1969-1972	Research Economist, Technical Associates, Inc.
1968-1969	Research Associate, Department of Economics, Virginia Polytechnic Institute and State University

ACADEMIC HONORS

Omicron Delta Epsilon - Honor Society in Economics
Beta Gamma Sigma - National Scholastic Honor Society of Business Administration
Alpha Iota Delta - National Decision Sciences Honorary Society
Phi Kappa Phi - Scholastic Honor Society

PROFESSIONAL DESIGNATIONS

Certified Rate of Return Analyst - Founding Member
Member of Association for Investment Management and Research (AIMR)

RELEVANT EXPERIENCE

Financial Economics -- Advised and assisted many Virginia banks and savings and loan associations on organizational and regulatory matters. Testified approximately 25 times before the Virginia State Corporation Commission and the Regional Administrator of National Banks on matters related to branching and organization for banks, savings and loan associations, and consumer finance companies. Advised financial institutions on interest rate structure and loan maturity. Testified before Virginia State Corporation Commission on maximum rates for consumer finance companies.

Testified before several committees and subcommittees of Virginia General Assembly on numerous banking matters.

Clients have included First National Bank of Rocky Mount, Patrick Henry National Bank, Peoples Bank of Danville, Blue Ridge Bank, Bank of Essex, and Signet Bank.

Published articles in law reviews and other periodicals on structure and regulation of banking/financial services industry.

Utility Economics -- Performed numerous financial studies of regulated public utilities. Testified in over 300 cases before some thirty state and federal regulatory agencies.

Prepared numerous rate of return studies incorporating cost of equity determination based on DCF, CAPM, comparable earnings and other models. Developed procedures for identifying differential risk characteristics by nuclear construction and other factors.

Conducted studies with respect to cost of service and indexing for determining utility rates, the development of annual review procedures for regulatory control of utilities, fuel and power plant cost recovery adjustment clauses, power supply agreements among affiliates, utility franchise fees, and use of short-term debt in capital structure.

Presented expert testimony before federal regulatory agencies Federal Energy Regulatory Commission, Federal Power Commission, and National Energy Board (Canada), state regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Hampshire, New Jersey, New Mexico, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Washington, Wisconsin, and Yukon Territory (Canada).

Published articles in law reviews and other periodicals on the theory and purpose of regulation and other regulatory subjects.

Clients served include state regulatory agencies in Alaska, Arizona, Delaware, Missouri, North Carolina, Ontario (Canada), and Virginia; consumer advocates and attorneys general in Alabama, Arizona, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maryland, Nevada, New Mexico, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, and West Virginia; federal agencies including Defense Communications Agency, the Department of Energy, Department of the Navy, and General Services Administration; and various organizations such as Bath Iron Works, Illinois Citizens' Utility Board, Illinois Governor's Office of Consumer Services, Illinois Small Business Utility Advocate, Wisconsin's Environmental Decade, Wisconsin's Citizens Utility Board, and Old Dominion Electric Cooperative.

Insurance Economics -- Conducted analyses of the relationship between the investment income earned by insurance companies on their portfolios and the premiums charged for insurance. Analyzed impact of diversification on financial strength of Blue Cross/Blue Shield Plans in Virginia.

Conducted studies of profitability and cost of capital for property/casualty insurance industry. Evaluated risk of and required return on surplus for various lines of insurance business.

Presented expert testimony before Virginia State Corporation Commission concerning cost of capital and expected gains from investment portfolio. Testified before insurance bureaus of Maine, New Jersey, North Carolina, Rhode Island, South Carolina and Vermont concerning cost of equity for insurance companies.

Prepared cost of capital and investment income return analyses for numerous insurance companies concerning several lines of insurance business. Analyses used by Virginia Bureau of Insurance for purposes of setting rates.

Special Studies -- Conducted analyses which evaluated the financial and economic implications of legislative and administrative changes. Subject matter of analyses include returnable bottles, retail beer sales, wine sales regulations, taxi-cab taxation, and bank regulation. Testified before several Virginia General Assembly subcommittees.

Testified before Virginia ABC Commission concerning economic impact of mixed beverage license.

Clients include Virginia Beer Wholesalers, Wine Institute, Virginia Retail Merchants Association, and Virginia Taxicab Association.

Franchise, Merger & Anti-Trust Economics -- Conducted studies on competitive impact on market structures due to joint ventures, mergers, franchising and other business restructuring. Analyzed the costs and benefits to parties involved in mergers. Testified in federal courts and before banking and other regulatory bodies concerning the structure and performance of markets, as well as on the impact of restrictive practices.

Clients served include Dominion Bankshares, asphalt contractors, and law firms.

Transportation Economics -- Conducted cost of capital studies to assess profitability of oil pipelines, trucks, taxicabs and railroads. Analyses have been presented before the Federal Energy Regulatory Commission and Alaska Pipeline Commission in rate proceedings. Served as a consultant to the Rail Services Planning Office on the reorganization of rail services in the U.S.

Economic Loss Analyses -- Testified in federal courts, state courts, and other adjudicative forums regarding the economic loss sustained through personal and business injury whether due to bodily harm, discrimination, non-performance, or anticompetitive practices. Testified on economic loss to a commercial bank resulting from publication of adverse information concerning solvency. Testimony has been presented on behalf of private individuals and business firms.

MEMBERSHIPS

American Economic Association
Virginia Association of Economists
Richmond Society of Financial Analysts
Financial Analysts Federation
Society of Utility and Regulatory Financial Analysts

Board of Directors	1992-2000
Secretary/Treasurer	1994-1998
President	1998-2000

RESEARCH ACTIVITY

Books and Major Research Reports

"Stock Price As An Indicator of Performance," Master of Arts Thesis, Virginia Tech, 1970

"Revision of the Property and Casualty Insurance Ratemaking Process Under Prior Approval in the Commonwealth of Virginia," prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Charles Schotta and Michael J. Ileo, 1971

"An analysis of the Virginia Consumer Finance Industry to Determine the Need for Restructuring the Rate and Size Ceilings on Small Loans in Virginia and the Process by which They are Governed," prepared for the Virginia Consumer Finance Association, with Michael J. Ileo, 1973

State Banks and the State Corporation Commission: A Historical Review, Technical Associates, Inc., 1974

"A Study of the Implications of the Sale of Wine by the Virginia Department of Alcoholic Beverage Control", prepared for the Virginia Wine Wholesalers Association, Virginia Retail Merchants Association, Virginia Food Dealers Association, Virginia Association of Chain Drugstores, Southland Corporation, and the Wine Institute, 1983.

"Performance and Diversification of the Blue Cross/Blue Shield Plans in Virginia: An Operational Review", prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Michael J. Ileo and Alexander F. Skirpan, 1988.

The Cost of Capital - A Practitioners' Guide, Society of Utility and Regulatory Financial

Analysts, 1997 (previous editions in 1991, 1992, 1993, 1994, and 1995).

Papers Presented and Articles Published

"The Differential Effect of Bank Structure on the Transmission of Open Market Operations," Western Economic Association Meeting, with Charles Schotta, 1971

"The Economic Objectives of Regulation: The Trend in Virginia," (with Michael J. Ileo), William and Mary Law Review, Vol. 14, No. 2, 1973

"Evolution of the Virginia Banking Structure, 1962-1974: The Effects of the Buck-Holland Bill", (with Michael J. Ileo), William and Mary Law Review, Vol. 16, No. 3, 1975

"Banking Structure and Statewide Branching: The Potential for Virginia", William and Mary Law Review, Vol. 18, No. 1, 1976

"Bank Expansion and Electronic Banking: Virginia Banking Structure Changes Past, Present, and Future," William and Mary Business Review," Vol. 1, No. 2, 1976

"Electronic Banking - Wave of the Future?" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 1, 1976

"The Pricing of Electricity" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 2, 1976

"The Public Interest - Bank and Savings and Loan Expansion in Virginia" (with Richard D. Rogers), University of Richmond Law Review, Vol. 11, No. 3, 1977

"When Is It In the 'Public Interest' to Authorize a New Bank?", University of Richmond Law Review, Vol. 13, No. 3, 1979

"Banking Deregulation and Its Implications on the Virginia Banking Structure," William and Mary Business Review, Vol. 5, No. 1, 1983

"The Impact of Reciprocal Interstate Banking Statutes on The Performance of Virginia Bank Stocks", with William B. Harrison, Virginia Social Science Journal, Vol. 23, 1988

"The Financial Performance of New Banks in Virginia", Virginia Social Science Journal, Vol. 24, 1989

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CORPORATE FINANCE

Investment Grade

Moody's is the leading rating agency in the investment-grade corporate bond sector, with over 2,000 issuers rated from Aaa to Baa globally. We rate an estimated 90% of public market bonds and our in-depth issuer reports cover 80% of the market. Moody's Investment-Grade Research service includes access to all Moody's analysts globally, timely rating updates, frequent industry reports, issuer specific special commentary, investor conferences...more

HIGHLIGHTS

1H08 tobacco industry report – outlook stable
The industry's profitability and cash-flow levels should remain relatively strong as price increases stick, supporting our stable outlook on credit fundamentals, we conclude. That said, we are concerned about declining cigarette-shipment volumes, especially as consumers look for ways to save money amid a weakening economy. Financial policies, including share repurchases and debt-financed acquisitions, may also become more aggressive as litigation risk moderates. *August report...* more

Survey: Rise in late payments to LDCs, but liquidity holds
Rising natural gas prices, deterioration in the housing market, and general economic weakness have put a strain on U.S. consumers, leading to above-average increases in past due payments, according to a survey of 31 Moody's-rated local gas distribution companies or LDCs. The study finds that these forces may not bode well for the 2008-2009 winter heating season. *August 7 press release...* more

Positive outlook for Japanese game software sector
The industry outlook for Japan's consumer game software sector is positive, as the launch of new consoles since late-2006 drives growth. In addition, activity has peaked domestically and is expected to remain strong overseas. By contrast, the rating outlook is stable with no major rating actions expected over the coming 12 months, based on our view that rated companies will minimize fluctuations in both revenue and earnings. *August 7 press release...* more

- Corporate Finance
  - Investment Grade
  - Leveraged Finance
  - Syndicated Loans
  - Global Infrastructure Finance
- Research
  - Ratings News
  - Special Reports
  - Rating Methodologies
- Index of Special Reports - Corporate Finance
- Events
- Subprime & the Credit Markets
- Watchlist
- Covenant Home Page
- Financial Metrics
- Rating Definitions
- Key Contacts

Back to Top

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Table of Contents

CHARTS

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MOODY'S® BOND RATINGS

Purpose: The system of rating securities was originated by John Moody in 1909. The purpose of Moody's® Ratings is to provide the investors with a simple system of gradation by which the relative investment qualities of bonds may be noted.

Rating Symbols: Gradations of investment quality are indicated by rating symbols, each symbol representing a group in which the quality characteristics are broadly the same. There are nine symbols as shown below, from that used to designate least investment risk (i.e., highest investment quality) to that denoting greatest investment risk (i.e., lowest investment quality):

Aaa Aa A Baa Ba B Caa Ca C

For explanation of municipal rating symbols, in particular the A 1 and Baa 1 groups see page 6

Absence of Rating: Where no rating has been assigned or where a rating has been suspended or withdrawn, it may be for reasons unrelated to the quality of the issue.

Should no rating be assigned, the reason may be one of the following:

1. An application for rating was not received or accepted.
2. The issue or issuer belongs to a group of securities or companies that are not rated as a matter of policy.
3. There is a lack of essential data pertaining to the issue or issuer
4. The issue was privately placed, in which case the rating is not published in Moody's® publications.

Suspension or withdrawal may occur if new and material circumstances arise, the effects of which preclude satisfactory analysis; if there is no longer available reasonable up-to-date data to permit a judgment to be formed; if a bond is called for redemption; or for other reasons.

Changes In Rating: The quality of most bonds is not fixed and steady over a period of time, but tends to undergo change. For this reason changes in ratings occur so as to reflect these variations in the intrinsic position of individual bonds.

A change in rating may thus occur at any time in the case of an individual issue. Such rating change should serve notice that Moody's® observes some alteration in the investment risks of the bond or that the previous rating did not fully reflect the quality of the bond as now seen. While because of their very nature, changes are to be expected more frequently among bonds of lower ratings than among bonds of higher ratings, nevertheless the user of bond ratings should keep close and constant check on all ratings both high and low ratings thereby to be able to note promptly any signs of change in investment status which may occur.

Limitations to Uses of Ratings: Bonds carrying the same rating are not claimed to be of absolutely equal quality. In a broad sense they are alike in position, but since there are a limited number of rating classes used in grading thousands of bonds, the symbols cannot reflect the fine shadings of risks which actually exist. Therefore, it should be evident to the user of ratings that two bonds identically rated are unlikely to be precisely the same in investment quality.

As ratings are designed exclusively for the purpose of grading bonds according to their investment qualities, they should not be used alone as a basis for investment operations. For example, they have no value in forecasting the direction of future trends of market price. Market price movements in bonds are influenced not only by the quality of individual issues but also by changes in money rates and general economic trends, as well as by the length of maturity, etc. During its life even the best quality bond may have wide price movements, while its high investment status remains unchanged.

The matter of market price has no bearing whatsoever on the determination of ratings which are not to be construed as recommendations with respect to "attractiveness." The attractiveness of a given bond may depend on its yield, its maturity date or other factors for which the investor may search, as well as on its investment quality, the only characteristic to which the rating refers.

Since ratings involve judgments about the future, on the one hand, and since they are used by investors as a means of protection, on the other, the effort is made when assigning ratings to look at "worst" potentialities in the "visible" future, rather than solely at the past record and the status of the present. Therefore, investors using the rating should not expect to find in them a reflection of statistical factors alone, since they are an appraisal of long term risks, including the recognition of many non-statistical factors.

Though ratings may be used by the banking authorities to classify bonds in their bank examination procedure, Moody's® Ratings are not made with these bank regulations in view. Moody's® Investors Service's own judgment as to desirability or non-desirability of a bond for bank investment purposes is not indicated by Moody's® Ratings.

Moody's® Ratings represent the mature opinion of Moody's® Investors Service, Inc., as to the relative investment classification of bonds. As such, they should be used in conjunction with the description and statistics appearing in Moody's® Manuals. Reference should be made to these statements for information regarding the issuer. Moody's® Ratings are not commercial credit ratings. In no case is default or receivership to be imputed unless expressly so stated in the Manual.

MOODY'S® SHORT-TERM DEBT RATINGS

Moody's® short-term debt ratings are opinions of the ability of issuers to repay punctually senior debt obligations. These obligations have an original maturity not exceeding one year, unless explicitly noted.

Moody's® employs the following three designations, all judged to be investment grade, to indicate the relative repayment ability of rated issuers:

Prime-1

Issuers rated **Prime-1** (or supporting institutions) have a superior ability for repayment of senior short-term debt obligations. Prime-1 repayment ability will often be evidenced by many of the following characteristics:

—Leading market positions in well-established industries.

—High rates of return on funds employed.

—Conservative capitalization structure with moderate reliance on debt and ample asset protection.

—Broad margins in earnings coverage of fixed financial charges and high internal cash generation.

—Well-established access to a range of financial markets and assured sources of alternate liquidity.

Prime-2

Issuers rated **Prime-2** (or supporting institutions) have a strong ability for repayment of senior short-term debt obligations. This will normally be evidenced by many of the characteristics cited above but to a lesser degree. Earnings trends and coverage ratios, while sound, may be more subject to variation. Capitalization characteristics, while still appropriate, may be more affected by external conditions. Ample alternate liquidity is maintained.

Prime-3

Issuers rated **Prime-3** (or supporting institutions) have an acceptable ability for repayment of senior short-term obligations. The effect of industry characteristics and market compositions may be more pronounced. Variability in earnings and profitability may result in changes in the level of debt protection measurements and may require relatively high financial leverage. Adequate alternate liquidity is maintained.

Not Prime

Issuers rated **Not Prime** do not fall within any of the Prime rating categories.

Moody's® makes no representation that rated bank or insurance company obligations are exempt from the registration under the U.S. Securities Act of 1933 or issued in conformity with any other applicable law or regulation. Nor does Moody's® represent that any specific bank or insurance company obligation is legally enforceable or a valid senior obligation of a rated issuer.

If an issuer represents to Moody's® that its short-term debt obligations are supported by the credit of another entity or entities, then the name or names of such supporting entity or entities are listed within the parentheses beneath the name of the issuer, or there is a footnote referring the reader to another page for the name or names of the supporting entity or entities. In assigning ratings to such issuers, Moody's® evaluates the financial strength of the affiliated corporations, commercial banks, insurance companies, foreign governments or other entities, but only as one factor in the total rating assessment. Moody's® makes no representation and gives no opinion on the legal validity or enforceability of any support arrangement.

Moody's® ratings are opinions, not recommendations to buy or sell, and their accuracy is not guaranteed. A rating should be weighed solely as one factor in an investment decision and you should make your own study and evaluation of any issuer whose securities or debt obligations you consider buying or selling.

BRANCH (DEPOSIT) OBLIGATIONS

Obligations of a branch of a bank are considered to be domiciled in the country in which the branch is located. Unless noted as an exception, Moody's® rating on a bank's ability to repay senior obligations extends only to branches located in countries which carry a Moody's® Sovereign Rating for Bank Deposits. Such branch obligations are rated at the lower of the bank's rating or Moody's® Sovereign Rating for Bank Deposits for the country in which the branch is located.

When the currency in which an obligation is denominated is not the same as the currency of the country in which the obligation is domiciled, Moody's® ratings do not incorporate an opinion as to whether payment of the obligation will be affected by actions of the government controlling the currency of denomination. In addition, risks associated with bilateral conflicts between an investor's home country and either the issuer's home country or the country where an issuer's branch is located are not incorporated into Moody's® short-term debt ratings.

MOODY'S® CORPORATE LONG-TERM RATINGS

Aaa

Bonds and preferred stock which are rated Aaa are judged to be of the best quality. They carry the smallest degree of investment risk and are generally referred to as "gilt edged." Interest payments are protected by a large or by an exceptionally stable margin and principal is secure. While the various protective elements are likely to change, such changes as can be visualized are most unlikely to impair the fundamentally strong position of such issues.

Aa

Bonds and preferred stock which are rated **Aa** are judged to be of high quality by all standards. Together with the **Aaa** group they comprise what are generally known as high grade bonds. They are rated lower than the best bonds because margins of protection may not be as large as in **Aaa** securities or fluctuation of protective elements may be of greater amplitude or there may be other elements present which make the long-term risk appear somewhat larger than the **Aaa** securities.

A

Bonds and preferred stock which are rated **A** possess many favorable investment attributes and are to be considered as upper-medium-grade obligations. Factors giving security to principal and interest are considered adequate, but elements may be present which suggest a susceptibility to impairment some time in the future.

Baa

Bonds and preferred stock which are rated **Baa** are considered as medium-grade obligations, (i.e., they are neither highly protected nor poorly secured). Interest payments and principal security appear adequate for the present but certain protective elements may be lacking or may be characteristically unreliable over any great length of time. Such bonds lack outstanding investment characteristics and in fact have speculative characteristics as well.

Ba

Bonds and preferred stock which are rated **Ba** are judged to have speculative elements; their future cannot be considered as well-assured. Often the protection of interest and principal payments may be very moderate, and thereby not well safeguarded during both good and bad times over the future. Uncertainty of position characterizes bonds in this class.

B

Bonds and preferred stock which are rated **B** generally lack characteristics of the desirable investment. Assurance of interest and principal payments or of maintenance of other terms of the contract over any long period of time may be small.

Caa

Bonds and preferred stock which are rated **Caa** are of poor standing. Such issues may be in default or there may be present elements of danger with respect to principal or interest.

Ca

Bonds and preferred stock which are rated **Ca** represent obligations which are speculative in a high degree. Such issues are often in default or have other marked shortcomings.

C

Bonds and preferred stock which are rated **C** are the lowest rated class of bonds, and issues so rated can be regarded as having extremely poor prospects of ever attaining any real investment standing.

Moody's® bond ratings, where specified, are applied to senior bank obligations and insurance company senior policyholder and claims obligations with an original maturity in excess of one year. Obligations relying upon support mechanisms such as letters-of-credit and bonds of indemnity are excluded unless explicitly rated.

Moody's® assigns ratings to individual long-term debt securities issued from medium-term note (MTN) programs, in addition to indicating ratings to MTN programs themselves. Notes issued under MTN programs with such indicated ratings are rated at issuance at the rating applicable to all pari passu notes issued under the same program, at the program's relevant indicated rating, provided such notes do not exhibit any of the following characteristics listed below. For notes with any of the following characteristics, the rating of the individual note may differ from the indicated rating of the program:

1. Notes containing features which link the cash flow and/or market value to the credit performance of any third party or parties.
2. Notes allowing for negative coupons, or negative principal.
3. Notes containing any provision which could obligate the investor to make any additional payments.

Market participants must determine whether any particular note is rated, and if so, at what rating level. Moody's® encourages market participants to contact Moody's® Ratings Desks directly if they have questions regarding ratings for specific notes issued under a medium-term note program.

MOODY'S® MUTUAL FUND RATINGS

Moody's® Money Market and Bond Fund Ratings are opinions of the investment quality of shares in mutual funds and similar investment vehicles which principally invest in short-term and long-term fixed income obligations, respectively. As such, these ratings incorporate Moody's® assessment of a fund's published investment objectives and policies, the creditworthiness of the assets held by the fund, as well as the management characteristics of the fund. The ratings are not intended to consider the prospective performance of a fund with respect to appreciation, volatility of net asset value, or yield. The rating definitions are as follows:

Aaa

Money Market Funds and Bond Funds rated **Aaa** are judged to be of an investment quality similar to Aaa-rated fixed income obligations, that is, they are judged to be of the best quality.

Aa

Money Market Funds and Bond Funds rated **Aa** are judged to be of an investment quality similar to Aa-rated fixed income obligations, that is, they are judged to be of high quality by all standards.

A

Money Market Funds and Bond Funds rated **A** are judged to be of an investment quality similar to A-rated fixed income obligations, that is, they are judged to possess many favorable investment attributes and are considered as upper-medium-grade investment vehicles.

Baa

Money Market Funds and Bond Funds rated **Baa** are judged to be of an investment quality similar to Baa-rated fixed income obligations, that is, they are considered as medium-grade investment vehicles.

Ba

Money Market Funds and Bond Funds rated **Ba** are judged to be of an investment quality similar to Ba-rated fixed income obligations, that is, they are judged to have speculative elements.

B

Money Market Funds and Bond Funds rated **B** are judged to be of an investment quality similar to B-rated fixed income obligations, that is, they generally lack characteristics of the desirable investment.

MOODY'S® FUND MARKET RISK RATINGS

Money Market and Bond Mutual Funds

Moody's® Mutual Fund Market Risk (MR) ratings are opinions of the relative degree of volatility of a rated fund's net asset value (NAV). In forming an opinion on the fund's future price volatility, Moody's® analysts consider risk elements that may have an effect on a fund'snet asset value such as: interest rate risk, prepayment and extension risk, liquidity and concentration risks, currency risk and derivatives risk. The ratings are not intended to consider prospective performance of a fund with respect to price appreciation or yield.

MR1

Money Market Funds and Bond Funds rated **MR1** are judged to have very low sensitivity to changing interest rates and other market conditions.

MR2

Money Market Funds and Bond Funds rated **MR2** are judged to have low sensitivity to changing interest rates and other market conditions.

MR3

Money Market Funds and Bond Funds rated **MR3** are judged to have moderate sensitivity to changing interest rates and other market consitions.

MR4

Money Market Funds and Bond Funds rated **MR4** are judged to have high sensitivity to changing interest rates and other market conditions.

MR5

Money Market Funds and Bond Funds rated **MR5** are judged to have very high sensitivity to changing interest rates and other market conditions.

Note: A "+" modifier appended to the MR1 rating category denotes constant NAV money market funds and other qualifying funds.

MOODY'S® INSURANCE FINANCIAL STRENGTH RATINGS

Moody's® Insurance Financial Strength Ratings are opinions of the ability of insurance companies to repay punctually senior policyholder claims and obligations. Specific obligations are considered unrated unless individually rated because the standing of a particular insurance obligation would depend on an assessment of its relative standing under those laws governing both the obligation and the insurance company. It is important to note that Moody's® makes no representation that rated insurance company obligations are exempt from registration under the U.S. Securities Act of 1933 or issued in conformity with any other applicable law or regulation. Nor does Moody's® represent that any specific insurance company obligation is legally enforceable or a valid senior obligation of a rated issuer.

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November 30, 2007

U.S. Utilities Ratings Analysis Now Portrayed In The S&P Corporate Ratings Matrix

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U.S. Utilities Ratings Analysis Now Portrayed In The S&P Corporate Ratings Matrix

The electric, gas, and water utility ratings ranking lists published today by Standard & Poor's U.S. Utilities & Infrastructure Ratings practice are categorized under the business risk/financial risk matrix used by the Corporate Ratings group. This is designed to present our rating conclusions in a clear and standardized manner across all corporate sectors. Incorporating utility ratings into a shared framework to communicate the fundamental credit analysis of a company furthers the goals of transparency and comparability in the ratings process. Table 1 shows the matrix.

Table 1

Business Risk/Financial Risk

	Financial Risk Profile				
Business Risk Profile	**Minimal**	**Modest**	**Intermediate**	**Aggressive**	**Highly leveraged**
Excellent	AAA	AA	A	BBB	BB
Strong	AA	A	A-	BBB-	BB-
Satisfactory	A	BBB+	BBB	BB+	B+
Weak	BBB	BBB-	BB+	BB-	B
Vulnerable	BB	B+	B+	B	B-

The utilities rating methodology remains unchanged, and the use of the corporate risk matrix has not resulted in any changes to ratings or outlooks. The same five factors that we analyzed to produce a business risk score in the familiar 10-point scale are used in determining whether a utility possesses an "Excellent," "Strong," "Satisfactory," "Weak," or "Vulnerable" business risk profile:

- Regulation,
- Markets,
- Operations,
- Competitiveness, and
- Management.

Regulated utilities and holding companies that are utility-focused virtually always fall in the upper range ("Excellent" or "Strong") of business risk profiles. The defining characteristics of most utilities--a legally defined service territory generally free of significant competition, the provision of an essential or near-essential service, and the presence of regulators that have an abiding interest in supporting a healthy utility financial profile--underpin the business risk profiles of the electric, gas, and water utilities.

As the matrix concisely illustrates, the business risk profile loosely determines the level of financial risk appropriate for any given rating. Financial risk is analyzed both qualitatively and quantitatively, mainly with financial ratios and other metrics that are calculated after various analytical adjustments are performed on financial statements prepared under GAAP. Financial risk is assessed for utilities using, in part, the indicative ratio ranges in table 2.

Table 2

Financial Risk Indicative Ratios - U.S. Utilities

(Fully adjusted, historically demonstrated, and expected to consistently continue)

	Cash flow		Debt leverage
	(FFO/debt) (%)	(FFO/interest) (x)	(Total debt/capital) (%)
Modest	40 - 60	4.0 - 6.0	25 - 40
Intermediate	25 - 45	3.0 - 4.5	35 - 50
Aggressive	10 - 30	2.0 - 3.5	45 - 60
Highly leveraged	Below 15	2.5 or less	Over 50

The indicative ranges for utilities differ somewhat from the guidelines used for their unregulated counterparts because of several factors that distinguish the financial policy and profile of regulated entities. Utilities tend to finance with long-maturity capital and fixed rates. Financial performance is typically more uniform over time, avoiding the volatility of unregulated industrial entities. Also, utilities fare comparatively well in many of the less-quantitative aspects of financial risk. Financial flexibility is generally quite robust, given good access to capital, ample short-term liquidity, and the like. Utilities that exhibit such favorable credit characteristics will often see ratings based on the more accommodative end of the indicative ratio ranges, especially when the company's business risk profile is solidly within its category. Conversely, a utility that follows an atypical financial policy or manages its balance sheet less conservatively, or falls along the lower end of its business risk designation, would have to demonstrate an ability to achieve financial metrics along the more stringent end of the ratio ranges to reach a given rating.

Note that even after we assign a company a business risk and financial risk, the committee does not arrive by rote at a rating based on the matrix. The matrix is a guide--it is not intended to convey precision in the ratings process or reduce the decision to plotting intersections on a graph. Many small positives and negatives that affect credit quality can lead a committee to a different conclusion than what is indicated in the matrix. Most outcomes will fall within one notch on either side of the indicated rating. Larger exceptions for utilities would typically involve the influence of related unregulated entities or extraordinary disruptions in the regulatory environment.

We will use the matrix, the ranking list, and individual company reports to communicate the relative position of a company within its business risk peer group and the other factors that produce the ratings.

FitchRatings
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Corporate Finance

Global Power
Criteria Report

Credit Rating Guidelines for Regulated Utility Companies

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Related Research
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- Post-Maintenance Interest Coverage Ratios for UK Utilities, Feb. 28, 2007.
- Equity Credit for Hybrid and Other Capital Securities, Sept. 27, 2006.
- Operating Leases: Updated Implications for Lessees Credit, Dec. 20, 2006.
- Evaluating Liquidity in the Power and Gas Sector, Sept 1, 2005.
- Cash Flow Measure in Corporate Analysis, Oct. 12, 2005.

■ Overview

These guidelines are an overview of Fitch Ratings' global approach to credit ratings for electric, natural gas and water utilities. This report updates and replaces Fitch's previously published credit rating criteria for regulated electric distribution companies and also covers vertically integrated electric utilities, natural gas distribution companies and water companies. The report also incorporates Fitch's methodology for evaluating corporate liquidity. Since utilities are significantly affected by local and national laws and regulations as well as regional and local consumption patterns and energy economics, Fitch also publishes periodic reports that explain the application of these guidelines to specific markets in many parts of the world.

The rating evaluation of an electric, gas or water utility considers the qualitative and quantitative risks associated with the company's business and corporate structure in combination with the company's financial strength and liquidity. The financial assessment emphasizes cash flow financial measures rather than equity or earnings-based ratios. The analytical focus is on the adequacy of the utility's cash flow relative to fixed charges, debt obligations and capital expenditures as well as its capital structure, liquidity and profitability.

The assessment of operating and business risks is an important element in determining ratings. This analysis is carried out using both quantitative and qualitative methods. Qualitative factors with the most significant effect on companies in the utilities sector include an evaluation of the regulatory and political environment in which the utility operates, including such factors as price-setting and cost-recovery mechanisms, transparency and predictability of the regulatory regime, exposure to competition and the nature of the customer franchise. In addition, Fitch's operational and business evaluation considers the degree to which the utility bears financial exposure to variations in commodity costs and in the case of network businesses, the responsibility for reliable supply. The business risk profile is also influenced by factors such as customer demographics, the type and quality of assets, operating performance, fuel mix, exposure to hydrological risks and management's strategy and capability. Each of these factors will affect the predictability or volatility of a utility's cash flow.

The assessment of operating risk also includes a review of the historical volatility of operating cash flow, when available, compared to the historical trend of similar companies. Fitch analysts review past cash flow trends to assess how the volatility or stability has been affected by the aforementioned fundamental factors. The assessment incorporates analytical judgment about how fundamental factors may affect the company's future operating cash flow.

Another important step in the rating process is an assessment of the utility's legal and corporate structure. Fitch's analysis focuses on the extent to which the utility's rating is aided by the financial support of a parent, sovereign or subsovereign entity, insulated from other group members through ring-fencing mechanisms or burdened by the weak condition of its parent, subsidiaries or affiliates. This assessment can either raise or lower the rating that would otherwise result from the analysis of an entity's stand-alone financial condition and business risk position.

Because regulated utilities typically enjoy more stable and predictable cash flows than industries that are highly competitive, cyclical or with less predictable demand, utilities in favorable regulatory and legal jurisdictions have the ability to support increased leverage and enjoy higher ratings than industrial companies with similar financial metrics. Regulated utilities in developed nations generally merit issuer default ratings (IDR) in the investment-grade categories, typically ranging from 'AA–' to 'BBB–', but there is no global norm.

Regulated Utility Qualitative Risk Factors

While regulated utilities generally have more stable and predictable cash flows than companies in many other industries, it would be a mistake to view all regulated utilities as identically low-risk businesses. A number of credit concerns exist for regulated utilities, including:

Regulatory Risk

Among the largest risks of regulated utilities are unfavorable regulatory policy and unpredictable regulatory outcomes (lack of "transparency" in the regulatory process). If the jurisdiction's rate-setting climate is confiscatory or capricious, a utility cannot uproot its assets and move to a more attractive jurisdiction. A utility may be obliged to meet levels of service quality or specific investment levels that exceed the utility's financial capability or ability to attract capital. In mature markets, if the goal of the regulatory authority is to reduce end-user prices, utility tariffs may be ratcheted downward to the point that no further economies can be wrung out of the expense base and profit margins and financial protection measures are eroded as a result. Disallowing prudently incurred costs would cause similarly unfavorable results.

Commodity Price/Market Risk

Some utilities are exposed to significant commodity price risks, while others have access to hedging mechanisms, such as the ability to pass through to consumers changes in fuel or purchased power costs or in the case of some distribution/retail companies, the actual cost of supplying electricity or natural gas. This is a major variable in comparing the risk of electric and gas utilities. When commodity costs are rising, the frequency of fuel adjustments is particularly important. Utilities insulated from market price exposure will be able to carry more leverage at a particular credit rating level than those exposed to market price risk. However, in a high or rising commodity cost environment, even utilities that are able to recover commodity costs from end-use customers are subject to higher working capital requirements associated with regulatory lag, depressed customer demand and increased bad debt expense, which may not be recoverable in rates. Finally, utilities typically collect revenues in local currency, and emerging market utilities can be exposed to currency devaluation if they have fixed costs or debt in nonlocal currencies.

Operating Risk

For electric utilities, the threat of a prolonged unplanned outage of a key operating facility is a significant credit risk. If an electric generating unit is out of service for an extended period, replacement power costs could be significant, particularly during peak heating or cooling seasons. In the case of large coal- or nuclear-fueled base-load generating units, an outage could drive up regional power prices, exacerbating the higher cost of replacement power. Even for a company with an effective fuel-adjustment mechanism, regulatory lag can strain liquidity and/or regulators may disallow cost recovery if the outage is deemed to have been the result of imprudent behavior on the part of the operator. Base-load generating units that represent a significant concentration of a company's asset base pose the greatest risk. Extensive damage to a transmission or distribution network related to a storm or disaster may also result in temporary stress. The exposure is greatest for the rural or remote parts of a network system, particularly those in mountainous terrain that is difficult to access. Even if regulators permit cost recovery, some regulatory lag is likely. To a lesser extent, system damage is also an issue for natural gas utilities, most notably in storm or flood-prone regions. Depending on the regime, water utilities may face hydrological risks both in terms of the availability and price of bulk water purchased and volume risk associated with lower demand if water usage restrictions are required in times of drought.

Competition, Obsolescence and Technology Risk

In many jurisdictions, network utilities are granted an exclusive monopoly franchise to serve all needs of consumers within a geographical footprint. In some cases, consumers may have the option to switch their service to a competitor. Even where a utility holds an exclusive franchise to serve consumers, a substitute energy supply may compete directly (for example, natural gas delivered by pipes in competition with bottled gas, oil, kerosene or electricity). The more essential the service is to consumers and the less subject it is to competition, the more stable and secure the utility's business profile becomes.

Although not an immediate concern, long-term credit ratings of electric utilities should consider the exposure over the long term to technology risk. Potential competitors for electric service include on-site industrial generation, generation of electricity using microturbines or fuel cells, on-site solar or wind production of energy, or installation of more energy-efficient appliances or industrial processes. In most areas, significant bypass of the wired distribution network is not currently commercially feasible, although some new technologies are becoming economically competitive in remote areas and under special circumstances. Customers will have a greater economic motivation to invest in new equipment or alternate energy supplies if the regulated utility tariff is uneconomically high (e.g., a tariff that incorporates high competitive transition charges, cross-subsidies to another class of customers or subsidies for social welfare costs, such as universal service).

Mergers and Acquisitions

There are numerous examples of consolidation mergers that resulted in more efficient companies with stronger operating expertise and financial and capital resources. Conversely, consolidation often creates new credit risks, such as management distraction, difficulty in achieving expected synergies, inflated acquisition prices and increased financial leverage, unfavorable treatment by regulators and the credit risk of a combination with a financially weaker company.

■ Credit Rating Criteria for Utilities

Corporate/Legal Structure

The corporate structure of a utility can have a significant effect on credit ratings. In some cases, the utility may be a subsidiary of a parent holding company, with other subsidiaries engaged in a variety of businesses. In other cases, the utility is a parent, with subsidiaries or divisions engaged in competitive and nonregulated businesses. Fitch's analysis focuses on the extent to which the utility's rating is aided by the financial support of a parent or burdened by the weak condition of its parent, subsidiaries or affiliates.

Among the important considerations is the extent to which a utility's access to capital may be damaged by the financial difficulties of a parent or affiliate and/or whether the utility is dependent on the parent for equity to support capital expenditures. The analysis also considers whether the corporate parent relies on utility dividends to support other regulated or unregulated subsidiary operations. In cases that Fitch determines there is a significant business with financial or legal interdependence, the rating differential between a utility and its parent or a utility and its subsidiary is likely to be limited. If financing occurs at the parent for all entities, or where significant cross-subsidies between the utility and its affiliates occurs, a consolidated rating is likely.

The legal analysis considers national laws that vary among countries and define the extent to which parents may be held responsible for the debt of subsidiaries or circumstances in which subsidiaries are responsible for the liabilities of a parent or affiliate. Public service entities may be subject to normal credit rights and bankruptcy laws, as is the case in the United States, or exempt from foreclosure or normal creditor remedies. In some jurisdictions, such as the UK, the government may have the right to impose a special administrator, whose principal responsibilities may be more closely aligned to ensuring continuity of supply rather than ensuring maximum recovery for creditors. Fitch considers these legal and structural issues to determine to what degree a utility's rating is affected by the credit quality of its parent or affiliate.

Statutes, regulatory laws or terms of the utility concession may restrict transactions between a utility and its corporate parent (or subsidiaries or affiliates), limit the maximum amount of debt permitted to be owed by the utility and control the amount of dividends and distributions from the utility. Similar restrictions may be contained in bond indentures or bank credit agreements. Rules of this type are said to "ring fence" the utility and support the utility's credit quality. If sufficiently strict, these constraints may insulate the utility from the direct effect of the lower credit rating of its parent or affiliates.

Regulatory Environment

Regulation is a key factor in determining credit ratings for utilities. In evaluating the regulatory environment, Fitch considers the laws that dictate the terms and conditions of providing utility service as well as commonly employed policies and recent regulatory actions. The review of the regulatory environment is incorporated into the analysis of the business risk and financial condition of the utility. Fitch conducts the regulatory assessment on:

- A national basis, if utilities are regulated on a common basis nationally, with a single methodology that encompasses all utilities, as seen, for example, in the UK, Chile and Argentina.
- A statewide basis, if all utilities in a state are regulated similarly.
- A utility by utility basis, if the regulatory regime is unique to each utility.

Franchise or Concession Terms

Typically, regulated utilities serve customers pursuant to a franchise or concession, which may be exclusive or nonexclusive. In the case of a nonexclusive franchise, it is important to review the conditions under which a competing provider may offer service. For example, in Chile, the regulatory authority may grant permission to a second distribution utility to build facilities and extend service to new customers upon demonstrating that it is in the public interest and would be more efficient for the electric system as a whole. In practice, this usually affects only service expansion to remote communities near the boundaries of two utilities' franchise areas. Of greater credit concern is a situation where dual facilities compete.

A concession or franchise may be limited to a fixed term or exist in perpetuity, absent evidence of poor service quality. If there is a limit to the term of the franchise, it is important to consider that in the debt structure and credit evaluations.

In an increasing number of jurisdictions, retail franchises are being opened up to full or partial competition. The pace of deregulation and the company's competitive position will determine whether the process has a material impact on the cash flows of the business.

Price Setting

Fitch's review of a regulated utility includes consideration of the tariff-setting process established by law or regulatory order and the past record of regulatory actions, such as the following:

- Under cost-of-service regulation, tariffs are set by the regulatory body at a level to allow the utility to recover reasonable expenses and earn a fair return on invested capital.
- A variant on cost-of-service tariffs incorporates incentive mechanisms (sometimes called "performance-based rate-making"), permitting the utility to retain a portion or all of its' cost savings within a fixed band, while the balance of any cost savings is passed on to consumers in lower prices.
- Under price cap regulation, a maximum price is set for each individual utility. Utilities with the ability to keep expenses low or expand sales can enhance their profit and retain any additional revenues until the next price reset. However, if the price cap is set very low to capture all the expected future productivity improvements, some utilities may not even be able to earn a reasonable return on investment. Under the UK model (also common in Australia), the price cap is set for five years with a one-time price adjustment at the beginning of this period. The tariff automatically adjusts annually thereafter by an inflation index plus or minus a given factor ("x" factor). The initial price and the "x" factor are a function of the expected change in cost base of the utility (including assumed efficiencies) and the required return on and of capital over the period.

Whatever mechanisms are used for setting prices, the most important element in assessing regulatory climate within a particular jurisdiction is the extent to which regulators set prices at levels that allow utilities a reasonable opportunity to recover costs in a timely manner and earn a return on capital investment consistent with the level of risk. To the extent that a performance-based ratemaking or price cap program provides the utility an incentive for efficient operation, Fitch views that as a positive factor. Furthermore, credit quality is enhanced if the tariff for each type of customer reflects the true economic costs of providing service and one set of customers is not subsidizing others. When cross-subsidies exist among customer classes, customers with uneconomically high tariffs will have an economic incentive to reduce consumption, self-generate or seek alternate energy sources.

Among the tariff-setting practices that can affect the adequacy of price levels and are considered important by Fitch are the expected returns on capital relative to the industry average and the level of risk, the ability to pass through fuel and purchased power and other operating costs (see Commodity Price Exposure section on page 6), and the timing and adequacy of cash recovery of invested capital.

Tariff design, which can affect a utility's cash flow, is also considered. The tariff may be structured with a greater or smaller proportion variable to the volume of energy consumption or, in rare cases, as a flat fee insensitive to the amount of energy consumed. If a high proportion of the tariff is tied to energy consumption, the utility's cash flow may be highly sensitive to fluctuations in weather (for household and small business customers) and industrial activity (for manufacturers and extractive industries).

In mature markets, the volume of consumption and number of customers connected to the system will be relatively stable over time. However, in developing markets, moderate and consistent growth in per capita consumption and the customer base may lead to material volume growth. In such cases, a higher volume-related component in the tariff mitigates some of the risk of higher than expected demand leading to greater infrastructure investment requirements. Conversely, explosive growth in demand for service may produce soaring capital expenditure requirements that surpass the available cash flow. However, economic crises can shrink the volume of consumption, with a severe effect on a volume-sensitive tariff.

Potential for Regulatory Change

The final step in the regulatory assessment process is an evaluation of the potential for future statutory or regulatory changes. Sometimes public policy provides a safety net, protecting investors in utilities by providing compensation to utilities for investments determined uneconomical by any change in the rules. However, investors have at times been exposed to investment losses when the regulatory model changed without adequate compensation for investors who had invested in good faith based on the earlier framework.

In many developed nations, the outlook of individual utilities could change as a result of continuing adjustments in the industry structure. While there is a high degree of confidence that electric or gas consumers will remain connected to the distribution system of their local utility for the foreseeable future, competition has been introduced for some traditional distribution utility functions, such as retailing, metering, billing and energy services.

At some point, policy changes or future technology developments may lead to the migration of customers away from the wired distribution of electricity or distribution of natural gas over a public network, which could create a new round of stranded costs relating to utility assets. Whether regulatory price-setting would or could keep utilities economically whole in the face of a long, slow decline in sales due to competition from other fuels or self-generation is open to question.

Service Area Demographics

A regulated utility has a substantial, immovable fixed investment tied to a specific region and dedicated to serving a population of current and potential customers. Therefore, it is important to analyze the potential customer base and penetration of electric and gas service within it as well as population density and trends in the per capita usage of electricity and natural gas by consumers. Additionally, population trends, such as growth rates, migration and new housing starts, are indicators of the vitality of a consumer base. Also important are wealth indices, principally reflected as per capita and disposable income and employment and unemployment rates, since these factors affect consumers' ability to pay for utility service and the willingness of regulators to permit tariff increases. Trends in wealth indexes are predicted by studying such factors as new business formation, job creation and the health of the regional industrial economy.

Consumers of electricity and natural gas may include households, small-commercial businesses, very large office buildings, retail establishments, hospitals, small manufacturers, agriculture and irrigation, or large manufacturers and extractive industries. Each customer category exhibits a different demand profile (seasonality of demand, pattern of consumption during the day or week, sensitivity to business and industrial cycles, and sensitivity to weather). Consumption trends by category of customer over time are a part of the business review. This includes the analysis of the share of total unit volume sales per customer category, the share of sales' revenues relating to each customer category, and the average realized price or gross margin per customer in each category.

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In some cases, a substantial portion of the utility's sales depends on a handful of extremely large customers. For example, in a region whose major industry is primary metal mining, milling and smelting operations, a downturn in commodity prices could result in the closure of a facility, affecting the utility's sale to the industrial operation as well as eliminating jobs and reducing the ability of household consumers and small businesses to afford electric, gas and water service. Therefore, utilities with a more diverse customer base (i.e., without large customer concentration in a single business or industry) tend to have more stable and predictable cash flows over time and typically enjoy higher credit ratings.

In some regions, consumers may have greater opportunities to install self-generation or switch to competing fuels, thus eliminating their consumption of electricity or natural gas distributed over the shared network. In addition, if another utility serves the region or a nearby region, the legal possibility and economic incentives for customers to seek service from the other utility (risk of bypass) must be considered. In the case of utilities with nonexclusive franchises, this analysis becomes even more important.

Energy Supply

In the case of electric and gas distribution systems, Fitch's credit analysis considers the availability of a reliable power or commodity supply.

For gas distributors, the availability of a continuing source of natural gas is a paramount concern. This involves a study of proven and probable reserves of natural gas in the relevant supply areas, exploration and drilling activity, and producers' success in finding new reserves to replace consumption, gas pipeline access and sources of gas imports. Supply can be disrupted when imports are reduced or blocked due to changes in national policies or international disputes, for example. For some electric distribution utilities, the diversity or stability of power supply and the access to and reliability of sufficient power transmission is of great importance.

Equally important is the degree to which the distributor is financially exposed to commodity supply costs. The analysis also considers the exposure to third-party energy suppliers that may default on their supply commitments under adverse circumstances. If a utility undertakes a voluntary competitive supply business, Fitch evaluates how the supply regime fits into the utility's overall strategic plan and whether the utility sufficiently managed upside opportunities and downside risks. If the utility is mandated to supply all consumption as a default provider or provider of last resort, the analysis focuses on determining whether the utility is reasonably assured of cost recovery and held harmless for actions, such as hedging activities, taken in good faith.

For integrated electric utilities that generate all or a substantial portion of the power needs of consumers, Fitch's credit analysis considers the fuel diversity and adequacy of the company's generating resources. The analytical focus is on the exposure to any particular fuel (see Commodity Price Exposure section), an extended outage of a large generating facility and the need for incremental generating capacity. Large new capacity requirements can drive future funding needs.

Commodity Price Exposure

Exposure to the cost of power or commodity supply may be mitigated by:

- Adjustment mechanisms that allow the utility to adjust its tariff periodically to match the cost of supplying power or natural gas.
- Ownership or control of generation capacity.
- Power or commodity supply contracts with reliable counterparties in volumes matching customers' expected demand (i.e., physical contracts).
- Options, futures or other derivatives (i.e., financial price risk management contracts), if available.

Ironically, even though each of these mitigating strategies reduces overall risk, additional risk may arise. For example, control and operation of power generation expose the utility to operating risk and ongoing capital spending requirements for future environmental compliance, while power and commodity supply contracts entail counterparty and settlement risk, and the utility may be exposed if the actual level of customer demand is lower or higher than the contracted supply.

In each case, Fitch analyzes the utility's supply responsibilities in conjunction with the hedging or risk-mitigation strategy. If a utility has a significant unhedged commodity price exposure or the hedging strategy introduces a meaningful level of risk, Fitch will increase the cash flow coverage ratios required and reduce the amount of debt leverage that the utility can support relative to a utility without similar exposure.

Operating Efficiency

Cost and quality of service is a meaningful indicator of business effectiveness and credit quality. If the utility has below-average reliability, it may be subject to financial penalties or a reduced allowed return. Furthermore, major customers may be motivated by power outages or variations in voltage and the quality of network-distributed power to install on-site generation facilities and cease business with the local utility. In some jurisdictions, failure to meet specified service quality standards can result in penalties or, in the extreme, the loss of the franchise or concession, or the regulatory body may grant permission for an adjacent utility to offer service to that utility's customers.

When utilities are subject to price cap or incentive rate-setting, a utility that can increase efficiency and reduce unit costs will be able to earn or exceed the regulatory return. Low-cost operations can also be helpful for utilities subject to cost-of-service regulation by reducing the necessity for rate increases. An efficient operator with lower tariffs will also face less resistance to rate increases and be better able to mitigate technological and bypass risks (customers will have less economic incentive to install new types of equipment or bypass the utility) as well as customer loss (industrial customers will have less incentive to relocate to another region with lower rates).

To measure the efficiency of a power utility's production facilities, Fitch considers the capacity and availability factors of its power generating facilities. Capacity and availability factors that meet or exceed the industry average are indicative of efficient operations. Utility power producers that are unable to achieve the industry norm are likely to incur higher purchased power and operating costs that may not be recoverable from rate payers. Thermal efficiency/heat rate, production costs (fuel plus operating and maintenance expense) per unit of output and revenue per unit of output are also used as measures of operating efficiency.

The quality and efficiency measures used to evaluate a power or gas distribution operation include measures of the frequency and duration of outages and the time to restore service after outages. Losses in transmission and distribution are also an efficiency measure, although these are often influenced by geographical factors or the nature of the network over which the utility has no control. Factors such as population density, number and diversity of customers served, geographic location and regulatory policies in the jurisdiction may skew efficiency measures and must be considered when assessing the efficiency of distribution operations. For example, a utility serving a dispersed customer base in a rural farming region is likely to have a higher average total cost of distribution service than another utility serving a densely populated metropolitan area. The higher cost of service for the rural low-density utility will reflect the greater number of distribution facilities needed to serve fewer customers per mile and is not necessarily representative of inefficient operations.

Very effective utilities have efficient billing systems and high collection rates. However, for utilities in emerging markets, the ability to bill and collect revenues may be undermined by factors, such as unfavorable regulatory policies and customers' economic stress, as well as by internal factors, including inadequate information systems and weak management controls. For electric utilities, the difference between the amount of energy purchased or produced and the amount billed to consumers is generally studied and broken down into technical losses (relating to physical characteristics) and nontechnical losses (theft of service and inadequate billing controls.)

The condition of the utility's assets is also considered in the operations review. Fitch does not conduct engineering evaluations, but evaluations performed by independent engineering consultants may be a factor in initial rating reviews. Typically, the condition of fixed assets and information systems is revealed by the network's performance on a day-to-day basis and manifested in the operating efficiency, service quality and outage statistics.

Management and Strategy

The primary focus of a utility's management should be providing the appropriate level of customer service and service quality. Management must ensure that profit or cost-cutting motives are balanced with the need to deliver service at a level of quality that comfortably exceeds the requirements of the regulatory body or terms of the utility's franchise or concession. Management must also ensure that customers' service expectations are met. The utility business is characterized by a high reliance on favorable relations with regulatory entities and political authorities, which is the responsibility of senior management. If a utility's managers are not viewed by the regulatory body as credible and trustworthy or are considered cavalier about the standards of service, there can be significant adverse consequences and financial effects.

If the utility is involved in the generation business, has energy supply responsibility or is a retailer, Fitch reviews the management information systems and control procedures used to measure and manage exposures to commodity price risk, counterparty risk and embedded options in commercial contracts. Senior managers and directors should have a full understanding of the business risks and receive frequent reports on potential exposures.

If the utility is involved in merger and consolidation activities or diversification into nonregulated business activities and these activities interfere with the primary mission or undermine the utility's financial well-being, the utility's ratings may be affected. Fitch assesses management's goals and business plan to determine whether the plan is well-suited to the utility's skills and resources. Also, the utility's strategic direction is analyzed as to its probable effect on the utility's risk profile and financial credit quality measures.

Financial Resources

After considering the qualitative and operating differences among utility companies, ratings are further distinguished by financial resources and performance. In evaluating the relative financial health of utility companies, Fitch focuses on the adequacy of cash flow to cover projected fixed costs and debt obligations under normal and stress circumstances. In Fitch's view, cash flow-based analysis provides the most accurate assessment of an issuer's ability to fund its business operations and meet debt service. Fitch ascribes greater importance to cash flow measures than to other more traditional earnings and capital structure indicators that play a secondary role in the rating analysis.

In assessing credit quality measures, historical and future trends are more important than a specific ratio at a given point in time. A review of historical financial measures is used to gauge the volatility or stability of the utility's cash flow and debt-service coverage ratios in past stress circumstances (e.g., extreme weather, tariff changes or economic recession). Then, Fitch reviews management's projections and constructs stress scenarios to test whether the entity's financial health would be materially impaired by a variety of adverse events, such as two or three years of unfavorable weather conditions, an adverse ruling in the next rate review or regulatory reset, lower industrial sales, higher operating costs or other risks specific to the utility's regulatory environment and business.

Capital Structure and Financial Flexibility

Fitch's evaluation of a utility's capital structure considers the type and amount of the utility's equity and debt in the context of the financial flexibility needed to balance the utility's operating cash flows, capital investment requirements, and possible and probable contingencies. Fitch also assesses debt type (secured or unsecured), maturity schedule and exposure to floating rate or foreign currency debt or refinancing risk. The debt maturity schedule should be sufficiently staggered so that the utility will not face the need to refinance substantial amounts of debt at a time when market conditions may be unfavorable or the utility's access to the bank market or capital market is constrained. If a significant amount of debt is denominated in a foreign currency, the utility should have a reasonable means of obtaining the foreign currency to pay interest and principal, and the analysis will incorporate stress cases testing the ability to cover obligations despite unfavorable exchange rates.

Financial Ratio Analysis

The financial analysis focuses on cash flow interest and fixed-charge coverage, leverage, liquidity and profitability. Fitch's financial analysis is cash flow-oriented but also incorporates traditional accrual accounting measures. Ratio calculations typically exclude items that Fitch deems as nonrecurring, such as asset impairments, restructuring charges, and gains and losses on asset sales. Adjustments are also made for securitization and operating lease transactions.

The cash flow analysis relies on funds flow from operations (FFO) and, to a lesser extent, earnings before interest, taxes, depreciation and amortization (EBITDA) as the primary indicators of a company's ability to generate funds from ongoing operations to service debt and fixed charges. Each measure is compared to interest, fixed charges and total debt to assess a company's leverage and interest protection.

FFO (as adjusted by Fitch) is derived from the consolidated statement of cash flow and is considered a more precise measure of the cash available to service debt, but the data needed may not be available in all jurisdictions. EBITDA is derived from figures on the income statement and is a rough but useful approximation of cash flow. Fitch adjusts

EBITDA and FFO by adding back rental expense or similar payments to form EBITDAR or FFO plus rents.

Fitch relies on several coverage ratios to assess a company's ability to meet its interest and fixed charge obligations: FFO interest coverage, FFO fixed-charge coverage, EBITDA interest coverage, EBITDAR fixed-charge coverage, and for utilities regulated on a UK-style basis post-maintenance interest charge coverage, which is FFO coverage, including a deduction for capital maintenance in the numerator (For additional details on post-maintenance interest coverage, please refer to Fitch's report "Post-Maintenance Interest Coverage Ratios for UK Utilities" dated Feb. 28, 2007.) Fixed charge coverage ratios include rental expense (both interest and principal amortization) in the numerator and denominator (For additional information, please refer to Fitch reports "Operating Leases: Updated Implications for Lessees Credit" dated Dec. 20, 2006 and "Cash Flow Measures in Corporate Analysis" dated Oct. 12, 2005). Interest expense is calculated before any credit (reduction) for capitalized interest and/or allowance for borrowed funds used during construction. EBITDA excludes nonrecurring nonoperating income.

Fitch's primary leverage measures are the ratios of FFO-to-debt (or debt-to-FFO), debt-to-EBITDA, debt-to-EBITDAR and for UK-style regulatory regimes debt-to-regulatory asset value (RAV). In each case, debt is adjusted to reflect debt equivalents and/or off-balance-sheet debt. Traditional balance-sheet measures of gross debt-to-capitalization and net debt-to-equity (gearing ratio) are also considered but given less weighting. These measures rely on the book value of equity, which is subject to variations in applications of accounting standards and may be less meaningful indicators of financial leverage.

Profitability is also an important financial measure. To attract capital and remain financially viable, utilities must operate profitably over the long term. Profitability is measured by return on average common equity, operating margin and return on assets.

Financial flexibility is more qualitative and is based on Fitch's assessment of capital market access, availability of bank facilities and a review of marketable assets. Fitch also assesses debt type (secured or unsecured), maturity schedule and exposure to floating-rate debt or refinancing risk.

Liquidity

Fitch expects a utility company to have sufficient liquidity to meet its normal business activities as well as cover adverse stress events. The liquidity analysis begins with a base case forecast of the company's expected FFO less its working capital needs, capital expenditures and dividends. The residual free cash flow or cash flow deficiency is matched against debt maturities to assess the sufficiency of internal cash sources to meet ongoing operating and financial obligations. The base case also considers the likely cash needs arising from contingent liabilities, such as guarantees and obligations of nonconsolidated affiliates important to the company's core business lines.

Fitch generally assumes that all cash on hand and available borrowing capacity under credit facilities may be used to cover cash deficits, subject to adjustments based on Fitch's evaluation of the company's ability to renew expiring credit facilities or meet conditions precedent to borrowing. Secondary funding sources, including asset sales, equity and debt issuance, and parent capital contributions as well as planned cash uses, such as equity repurchases or additional debt repayment, are also considered.

After evaluating the company's base case liquidity strength, Fitch considers additional stress case conditions that could further strain a utility's cash position, given its individual circumstances. The two broad categories of stress events are operational events and events relating to trading and marketing activities. The selected stress events have a reasonable probability, but not expectation, of occurring and the actual occurrence would result in a significant drain on cash liquidity.

Operational stresses include but are not limited to a prolonged unplanned outage at key operating facilities, severe price movements for an unhedged fuel need and the failure of a fuel or power supplier to make delivery or repair costs from a hurricane or serious storm. Adverse results in a pending investigation or lawsuit are also considered as a potential operational stress.

For companies that trade energy commodities Fitch considers the collateral requirements related to adverse market price movements and changes in credit ratings (for additional details on stress cases, please refer to Fitch's report, "Evaluating Liquidity in the Power and Gas Sector" dated Sept. 1, 2005).

Available liquidity for the stress analysis is limited to unrestricted cash and funds available under committed bank credit facilities. The expected loss related to the adverse stress scenario should be covered by the availability at least 1.0 times. In determining the adequacy of a utility's cash flow under stress conditions, Fitch recognizes that the company has the flexibility to lower its dividend payments, projected share buybacks and discretionary capital expenditures. Fitch assumes that in a stress scenario a company will draw on its bank lines to fund the liquidity needs, and will add the draw to the company's debt and reduce EBITDA for any anticipated earnings effect of the events.

Risk Assessment and Guideline Credit Ratios

Fitch analysts use benchmark credit ratios and comparisons with peer companies to compare utilities and related companies in the utilities sector. The benchmarks may differ in various jurisdictions and between different types of utilities. The benchmarks presume that companies with progressively higher variability of operating cash flow (higher business risk) have progressively lower debt capacity.

A quantitative approach is limited in some jurisdictions by the lack of sufficient data. For a company with no prior operating history, the experience of peer companies may provide a useful proxy, but in some markets undergoing restructuring, reliable peers may not be available. It should be noted that the same benchmarks cannot be applied directly to utilities in different nations or under different ownership situations. Currency and economic volatility and political risks vary from one nation to another and require adjustments in the standards, as do differences in tax circumstances, transparency of the regulatory regime, ownership structures (e.g., municipal, cooperative or state ownership) or implicit governmental support.

■ Financial Adjustments

Debt Equivalents

Fitch calculates a debt equivalent for certain off-balance-sheet and other debt-like obligations. The debt equivalent is calculated using the present value of the remaining rental obligation or a multiple of lease rental payments (commonly 8 times). For material lease obligations, the present value approach is the preferred methodology. Power plant tolling agreements are also capitalized using the present value approach. If the lessor is a special-purpose entity (SPE), the entire SPE is consolidated into the lessee. In each instance, an interest component is calculated and added to interest expense for the calculation of adjusted financial ratios. When using the present value approach, the discount rate is multiplied times the implied lease principal. When using a multiple of lease rental payments the entire rental payment is treated as interest expense. For more information, see Fitch's Criteria report, "Operating Leases: Updated Implications for Lessees' Credit," dated Dec. 20, 2006.

Nonrecourse Debt Obligations

Nonrecourse debt obligations are evaluated in terms of strategic relevance of the asset or business unit and the level of financial separation. If deemed noncore by Fitch, the debt can be deconsolidated. When a unit is determined to be of credit and debt is deconsolidated, all income and dividends are also excluded from financial projections.

Corporate Guarantees

Guaranteed debt of nonconsolidated entities is consolidated. With respect to performance guarantees, Fitch's analysts forecast whether there is any expected liability and if so, may consolidate the expected amount.

Hybrid Securities

Fitch gives equity credit to certain hybrid securities that are neither common stock nor ordinary debt. The equity credit consists of five classes: 100%, 75%, 50%, 25% and 0%. The proportion of equity credit is influenced by the convertibility or junior ranking, the interest/dividend deferral mechanism, the effective maturity and the absence of investor protections, such as covenants and cross defaults. In adjusting financial leverage and capital ratios Fitch uses the adjusted equity and debt derived from appropriate equity credit attributed to each hybrid security. Interest coverage is calculated in two alternate ways: with all interest or dividends included in the calculation of interest and fixed charges and with all deferrable dividends or interest eliminated. Fitch expects that 70% or more of the entity's equity capital will be in the form of common equity securities, since hybrid securities are most equity-like when the issuer is in distress but offer less support when the entity's financial condition is merely weakening. For additional information on Fitch's treatment of hybrid securities, please refer to the special report, "Equity

Credit for Hybrids and Other Capital Securities," dated Sept. 27 2006.

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U.S. Utilities Ratings Analysis Now Portrayed In The S&P Corporate Ratings Matrix

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The electric, gas, and water utility ratings ranking lists published today by Standard & Poor's U.S. Utilities & Infrastructure Ratings practice are categorized under the business risk/financial risk matrix used by the Corporate Ratings group. This is designed to present our rating conclusions in a clear and standardized manner across all corporate sectors. Incorporating utility ratings into a shared framework to communicate the fundamental credit analysis of a company furthers the goals of transparency and comparability in the ratings process. Table 1 shows the matrix.

Table 1

Business Risk/Financial Risk

	Financial Risk Profile				
Business Risk Profile	**Minimal**	**Modest**	**Intermediate**	**Aggressive**	**Highly leveraged**
Excellent	AAA	AA	A	BBB	BB
Strong	AA	A	A-	BBB-	BB-
Satisfactory	A	BBB+	BBB	BB+	B+
Weak	BBB	BBB-	BB+	BB-	B
Vulnerable	BB	B+	B+	B	B-

The utilities rating methodology remains unchanged, and the use of the corporate risk matrix has not resulted in any changes to ratings or outlooks. The same five factors that we analyzed to produce a business risk score in the familiar 10-point scale are used in determining whether a utility possesses an "Excellent," "Strong," "Satisfactory," "Weak," or "Vulnerable" business risk profile:

- Regulation,
- Markets,
- Operations,
- Competitiveness, and
- Management.

Regulated utilities and holding companies that are utility-focused virtually always fall in the upper range ("Excellent" or "Strong") of business risk profiles. The defining characteristics of most utilities--a legally defined service territory generally free of significant competition, the provision of an essential or near-essential service, and the presence of regulators that have an abiding interest in supporting a healthy utility financial profile--underpin the business risk profiles of the electric, gas, and water utilities.

As the matrix concisely illustrates, the business risk profile loosely determines the level of financial risk appropriate for any given rating. Financial risk is analyzed both qualitatively and quantitatively, mainly with financial ratios and other metrics that are calculated after various analytical adjustments are performed on financial statements prepared under GAAP.

Financial risk is assessed for utilities using, in part, the indicative ratio ranges in table 2.

Table 2

Financial Risk Indicative Ratios - U.S. Utilities

(Fully adjusted, historically demonstrated, and expected to consistently continue)

	Cash flow		Debt leverage
	(FFO/debt) (%)	(FFO/interest) (x)	(Total debt/capital) (%)
Modest	40 - 60	4.0 - 6.0	25 - 40
Intermediate	25 - 45	3.0 - 4.5	35 - 50
Aggressive	10 - 30	2.0 - 3.5	45 - 60
Highly leveraged	Below 15	2.5 or less	Over 50

The indicative ranges for utilities differ somewhat from the guidelines used for their unregulated counterparts because of several factors that distinguish the financial policy and profile of regulated entities. Utilities tend to finance with long-maturity capital and fixed rates. Financial performance is typically more uniform over time, avoiding the volatility of unregulated industrial entities. Also, utilities fare comparatively well in many of the less-quantitative aspects of financial risk. Financial flexibility is generally quite robust, given good access to capital, ample short-term liquidity, and the like. Utilities that exhibit such favorable credit characteristics will often see ratings based on the more accommodative end of the indicative ratio ranges, especially when the company's business risk profile is solidly within its category. Conversely, a utility that follows an atypical financial policy or manages its balance sheet less conservatively, or falls along the lower end of its business risk designation, would have to demonstrate an ability to achieve financial metrics along the more stringent end of the ratio ranges to reach a given rating.

Note that even after we assign a company a business risk and financial risk, the committee does not arrive by rote at a rating based on the matrix. The matrix is a guide--it is not intended to convey precision in the ratings process or reduce the decision to plotting intersections on a graph. Many small positives and negatives that affect credit quality can lead a committee to a different conclusion than what is indicated in the matrix. Most outcomes will fall within one notch on either side of the indicated rating. Larger exceptions for utilities would typically involve the influence of related unregulated entities or extraordinary disruptions in the regulatory environment.

We will use the matrix, the ranking list, and individual company reports to communicate the relative position of a company within its business risk peer group and the other factors that produce the ratings.

Moody's Investors Service

Global Credit Research
Credit Opinion
28 JUL 2008

Credit Opinion: Arizona Public Service Company

Arizona Public Service Company

Phoenix, Arizona, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	Baa2
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Subordinate Shelf	(P)Baa3
Commercial Paper	P-2
Parent: Pinnacle West Capital Corporation	
Outlook	Stable
Issuer Rating	Baa3
Sr Unsec Bank Credit Facility	Baa3
Senior Unsecured Shelf	(P)Baa3
Subordinate Shelf	(P)Ba1
Preferred Shelf	(P)Ba2
Commercial Paper	P-3

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Key Indicators

Arizona Public Service Company

ACTUALS	1Q08 LTM	2007	2006	2005
(CFO Pre-W/C + Interest) / Interest Expense [1][2]	4.4x	4.2x	4.4x	3.6x
(CFO Pre-W/C) / Debt [2]	19.6%	18.3%	19.0%	14.5%
(CFO Pre-W/C - Dividends) / Debt [2]	14.1%	14.0%	14.5%	9.7%
(CFO Pre-W/C - Dividends) / Capex [2]	56.0%	58.7%	79.0%	53.1%
Debt / Book Capitalization	45.9%	45.9%	46.0%	47.5%
EBITA Margin	21.7%	22.6%	23.9%	20.9%

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items [2] Changes in risk management and trading assets and liabilities are excluded from CFO Pre-W/C

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Corporate Profile

Arizona Public Service (APS: Baa2 senior unsecured, stable) is a vertically integrated electric utility that provides electric service to most of the state of Arizona with the major exceptions of about one-half of the Phoenix metropolitan area and the Tucson metropolitan area. APS is the primary subsidiary of Pinnacle West Capital Corporation (Pinnacle: Baa3 senior unsecured, stable), a holding company that through its other subsidiaries sells energy related products and services and develops residential and commercial real estate.

Recent Events

On July 25, 2008 Moody's revised the outlooks for APS and Pinnacle to stable from negative. The revision in outlook was a result of the companies' stable financial performance and also reflects our opinion of APS' improved prospects for more timely recovery of certain costs than had historically been the case. Our view is based on recent regulatory decisions involving recovery mechanisms for the cost of fuel and purchased power and transmission as well as recovery mechanisms for certain growth related costs. The outlook revision also recognized APS' demonstrated intent to attempt to minimize regulatory lag by filing for additional rate relief as soon as practicable.

Regulatory Activity

Approval of Line Extension Fees

In February 2008 the Arizona Corporation Commission (ACC) approved an amendment to APS' line extension schedule which eliminated certain free footage allowances and permitted APS to collect, on a current basis, costs relating to line extensions, which are estimated to be approximately $3,500 - $5,000 per new meter set (pre-tax). Moody's views the incremental (after-tax) cash flow resulting from these fees as recurring, and we have adjusted our credit metrics to reflect them as operating cash flows.

General Rate Case Filing

In June 2008, APS filed for a $278.2 million net rate increase (approximately 8.5% from existing customers) comprised of a $264.3 million non-fuel related increase and a $13.9 million net fuel-related increase. APS has proposed to collect up to $53 million of the increase specifically from new customers. The fuel increase request is net of approximately $170 million currently being collected in APS rates through its power supply adjustor (PSA) mechanism. APS' June filing is based on a test year ended December 2007. The request has been accepted by ACC Staff. A procedural schedule has been proposed with hearings in April 2009 and a decision expected in the latter part of 2009.

Request for Interim Increase

Also in June 2008, APS filed a request for an interim base rate increase of $.003987 per kWh to become effective upon the expiration of the $.003987 per kWh power supply adjustor surcharge currently in APS' rates. APS estimates the current surcharge will remain in effect through July. A procedural schedule has been set for this request, with hearings scheduled for September 2008 with a decision anticipated shortly thereafter.

Palo Verde

In February 2007, Nuclear Regulatory Commission (NRC) placed Palo Verde Unit 3 (PVU3), into the "multiple/repetitive degraded cornerstone" column of the NRC's action matrix, which has resulted in an enhanced inspection regimen and some increased operating costs for APS as it seeks to improve its processes at all three Palo Verde units. In February 2008, the NRC issued its revised confirmatory action letter, and as required, on March 31, 2008, APS submitted its revised improvement plan. The NRC will continue to provide increased oversight at Palo Verde until the facility has demonstrated sustained performance improvement. APS anticipates that this process will continue into 2009.

While operating performance at Palo Verde has improved, capacity factors continue to be impacted by planned outages (including a steam generator replacement in 2007) that have been extended by additional inspections. In 2007, the plant's average capacity factor was 79.0% versus 70.7% in 2006 and 77.4% in 2005. For the first quarter of 2008, the nuclear capacity factor was 93%.

Rating Rationale

The Baa2 rating for the senior unsecured obligations of APS reflects the stability of its regulated cash flows, the economic strength of its service territory, its regulatory environment, cash flow credit metrics that are appropriate

for the rating, and its position as a subsidiary of Pinnacle. The rating and outlook consider the traditionally challenging regulatory environment in Arizona, but also contemplates recent ACC decisions and regulatory activities that appear intended to reduce regulatory lag and provide more timely recovery of certain costs.

Given APS' current significant capital expenditure program, the company will require continued, timely regulatory support to maintain credit metrics that are appropriate for its rating. The stable outlook assumes APS will be reasonably successful in managing its regulatory relationships with an objective of achieving more timely recovery and an opportunity to earn a fair return. The rating also incorporates an expectation that APS will maintain a balanced approach with regards to financing its capital expenditures with a goal of maintaining or improving its current level of financial strength.

The most important drivers of the rating and outlook are as follows:

Regulatory Environment

Almost all of APS' operations are regulated which is generally viewed as positive for credit quality as regulated cash flows tend to be more stable and predictable than those of unregulated companies. This key factor is tempered somewhat by the historically challenging regulatory environment in Arizona, which Moody's ranks as below average for U.S. regulatory jurisdictions in terms of supportiveness or predictability and stability of regulated cash flows.

APS' operations are regulated by the ACC, an elected commission that has tended to render its decisions after prolonged consideration. Although regulatory lag remains a significant concern, recent decisions with regards to costs for fuel and purchased power and transmission, and certain growth related expenditures should reduce the time to recover some of these items.

General Regulatory Lag

APS' rate case activity is illustrative of an environment where there has tended to be below average assurance of timely recovery of costs and the ability to earn a reasonable return on investment. APS' 2003 rate case was not concluded until April 2005, and the increase received was less than half of the amount requested; the significant delay and relatively modest allowed increase resulted in the need for APS to quickly file another rate case in January 2006.

APS' January 2006 rate case was decided somewhat more quickly with a decision rendered in June 2007 wherein the utility received approximately three quarters of its requested increase; however, the allowed increase was almost entirely related to increased costs for fuel and purchased power. Of the $120 million requested for non-fuel items, only $7 million was approved. As a result, APS filed another general rate case as soon as practicable, based on a test year-ending September 2007. APS subsequently agreed with ACC Staff to re-file its rate increase request based on a test year-ending December 2007. Given the amount of time generally required to decide rate cases in Arizona, Moody's estimates that new rates will not be implemented until the latter part of 2009.

Reduced Regulatory Lag for Certain Items

The ACC's June 2007 decision included a significantly improved mechanism for the recovery of fuel and purchased power costs, incorporating a forward estimate of fuel costs in addition to the continued recovery of past deferrals. Fuel and purchased power costs have been among APS' most volatile operating expenses and Moody's views the ACC's recent approach to this problem as supportive of the utility's credit profile. However, we note that APS fuel recovery factor remains subject to an annual cap, potentially delaying recoveries beyond a one-year true-up period, and subject to a 90/10 sharing mechanism wherein 10% of costs are not able to be recovered.

In June 2008, APS requested an interim base rate increase that would take effect upon expiration in July 2008 of a surcharge being collected under the fuel clause adjustment mechanism. The request could potentially allow base rate cost recovery, subject to refund, prior to the completion of the next general rate case. This could result in a measure of rate stability as there could potentially be no immediate incremental increase to customers, and there would likely ultimately be a smaller base rate increase. Since the ACC and interested parties needed more time to consider this request, a decision is now expected late September to mid October. If implemented new rates could be in place November 1 when lower winter rates go into effect, thereby allowing some degree of rate stability. Moody's notes that the ACC has granted interim increases in the recent past. Moody's views mechanisms designed to reduce the time required to recover a utility's costs, such as the requested interim base rate increase a positive for credit quality.

In its June 2007 order, the ACC requested that APS propose mechanisms that could potentially allow growth to

pay for itself, rather than being paid by the current customer base. In February 2008, the ACC approved an amendment to APS' line extension schedule that should provide an almost immediate recovery of the cost of certain growth related capital investment reducing the amount of external financing needed to support these expenditures. Moody's views this revision as positive for credit, virtually eliminating the normal regulatory lag that would otherwise be associated with seeking recovery of these expenditures.

In its 2005 order, the ACC authorized a transmission tracking adjustment (TCA) mechanism designed to allow retail transmission charges to track those authorized by the FERC. The TCA was initially implemented in March 2008, and timely adjusted following an automatic adjustment in FERC transmission rates in June 2008.

Service Territory Growth Slowing

Growth in APS' service territory has slowed significantly below the 4-5% level experienced in 2005 and 2006. In 2007, customer growth was approximately 3%; for the first quarter of 2008 customer growth slowed to 2% and is not expected to return to historical heights over the near-to-medium term. Although, a growing customer base can provide a source of increased revenue, assuming timely recovery of increased growth related investment and increased costs for fuel and purchased power, it also has resulted in a continuing need for capital investment and regulatory relief. The stable outlook assumes APS will continue to take a balanced approach with regards to the funding of its capital expenditures. Moody's also believes a sustained period of slower growth could potentially temper APS need for capital investment which could reduce its financing requirements.

Financial Metrics

In 2004 and 2005, APS' key financial metrics reflected the fact that it had been unable to recover fully increased costs for fuel, purchased power and capital spending on a timely basis. For example, the ratio of cash from operations prior to changes in current assets and liabilities (CFO pre-WC) / debt (incorporating Moody's standard analytic adjustments) dropped into the mid-teens. Financial metrics improved in 2006 and 2007 with CFO pre - WC / debt moving to the upper-teens as fuel recovery improved. These metrics are now toward the middle-to-upper end of the 13% to 25% range identified in Moody's Rating Methodology for Global Electric Utilities for Baa rated entities on a stand-alone basis within the medium risk category. Cash flow credit metrics are expected to remain in that range over the near-to-medium term reflecting more timely cost recovery of certain items and assuming capital expenditures are financed in a manner that is also supportive of APS current financial strength and flexibility. In general, Moody's would look for APS to have financial metrics that are somewhat stronger than comparably rated utility operating companies that operate in regulatory environments that have historically been more supportive of credit quality.

Subsidiary of Pinnacle West

Pinnacle, APS' parent company, conducts a modest amount of non-regulated activities including power marketing and trading, sales of energy related products and services, and residential and commercial real estate development through subsidiaries including SunCor Development Company (real estate). However, for the past several years almost all of Pinnacle's cash from operations has been generated by APS. Over the near-to-medium term, Pinnacle's non-regulated businesses, are not expected to meaningfully contribute to, or detract from, consolidated cash flows. Although residential real estate sales slowed considerably in 2006, 2007 and continuing into 2008, Pinnacle's joint venture strategy with other developers, combined with its successfully completed asset sales program (implemented 2003-2005) has significantly reduced its exposure to this volatile sector. The parent company also maintains a modest amount of leverage with holding company debt at less than 10% of consolidated debt.

Liquidity Profile

APS' Prime-2 short-term rating for commercial paper reflects the relatively stable and predictable cash flow provided by its regulated electric utility operations.

For the year ended December 2007, APS' cash flow from operations of approximately $765 million covered approximately 72% of its outlays, including capital expenditures of approximately $900 million and dividends to Pinnacle of $170 million. The shortfall was funded via a combination of internal and external sources of cash including $218 million of short term debt proceeds, approximately $40 million of equity contributions from Pinnacle and cash on hand.

For the next several years, APS' capital expenditures are expected to be in the range of $1.0 billion per year, primarily to expand APS' transmission and distribution network to meet growing customer needs, but also to upgrade its existing utility properties and for other environmental purposes. Funding for these increased capital

expenditures is expected to be provided via a combination of internal and external sources of cash, including operating cash flow, equity contributions from Pinnacle and long and short term debt financing.

Over the last several years, APS has paid dividends to Pinnacle of $170 million per year. Moody's expects APS' dividends are likely to remain near this level in 2008 and over the medium term.

APS' pattern of cash flow is seasonal as the peak of electric demand occurs during the summer months due to high air conditioning load that exists in its service territory. As a result, the bulk of its commercial paper borrowings typically occur in the second and third quarters of each year. As of March 31, 2008, APS had $90 million of commercial paper and $100 of short-term debt outstanding under its revolving credit facility.

APS has historically maintained a very modest level of cash on its balance sheet; as of March 31, 2008, APS had reported cash and cash equivalents of approximately $8 million.

APS' commercial paper program is sized at $250 million and is currently supported by two committed lines of credit totaling $900 million, a $400 million line that expires in December 2010 and a $500 million line that expires in September 2011. As of March 31, 2008, APS had approximately $100 million of borrowings under its credit facilities. Overall availability under these credit facilities was $796 million, of which $90 million was back-stopping commercial paper outstanding. Both credit agreements have one financial covenant that requires the ratio of debt to total capitalization not to exceed 65%. As of March 31, 2008, APS' debt to total capitalization ratio, calculated in accordance with the credit documents, was approximately 47%. The credit agreements do not require a Material Adverse Change (MAC) representation for revolver borrowings. No rating triggers exist in any APS credit facilities though interest costs may increase under various financing agreements if a downgrade occurs. APS nearest long term debt maturity is $400 million of unsecured notes due in 2011. In 2010, APS must replace letters of credit supporting approximately $200 million of variable rate pollution control bonds.

APS' Prime-2 rating for its short term obligations assumes that the company will manage the amount of commercial paper and other near term obligations outstanding within the limits of its readily available sources of cash, including its committed bank credit facilities.

Rating Outlook

The stable outlook reflects the nature of APS' predominately regulated cash flows and Moody's view that its improved cash flow financial metrics are likely to be sustainable. The outlook assumes APS' will be reasonably successful in managing its regulatory relationships and that capital expenditures will be financed in a balanced manner with a goal of maintaining or improving APS current position of financial strength.

What Could Change the Rating - Up

APS' rating is not likely to be revised upward in the near-to-medium term. Longer term, if there is an increase in supportive regulatory treatment resulting in material, timely rate increases, or if there are material reductions in costs or leverage such that Moody's could anticipate key financial ratios improving significantly from their current levels, if for example, a ratio of CFO pre -WC / debt could be maintained in the mid twenty percent range.

What Could Change the Rating - Down

A downgrade could result if Palo Verde experiences an extended outage and APS is unable to recover, in a timely manner, higher maintenance and purchased power costs, or if APS' regulatory lag for capital spending becomes more pronounced. A downgrade could result if Moody's expects a sustained weakening of financial metrics, if for example, the ratio of CFO pre -WC / debt would remain in the mid-teens for an extended period.

Rating Factors

Arizona Public Service Company

62000

Select Key Ratios for Global Regulated Electric Utilities

Rating	Aa	Aa	A	A	Baa	Baa	Ba	Ba
Level of Business Risk	Medium	Low	Medium	Low	Medium	Low	Medium	Low

CFO pre-W/C to Interest (x) [1]	>6	>5	3.5-6.0	3.0-5.7	2.7-5.0	2-4.0	<2.5	<2
CFO pre-W/C to Debt (%) [1]	>30	>22	22-30	12-22	13-25	5-13	<13	<5
CFO pre-W/C - Dividends to Debt (%) [1]	>25	>20	13-25	9-20	8-20	3-10	<10	<3
Total Debt to Book Capitalization (%)	<40	<50	40-60	50-70	50-70	60-75	>60	>70

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

AUS

AUGUST 2008

AUS UTILITY REPORTS
THE INVESTOR'S EDGE

AUS MONTHLY UTILITY REPORT

ELECTRIC COMPANIES

NATURAL GAS COMPANIES

TELEPHONE COMPANIES

WATER COMPANIES

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ELECTRIC COMPANIES

COMPANY	TOTAL REV $ MILL (1)	REG ELEC REV	NET PLANT $ MILL	NET PLANT PER $ REV (1)	S&P BOND RATING	MOODY'S BOND RATING	COMMON EQUITY RATIO (3)	% RETURN ON BOOK VALUE: COMMON EQUITY (4)	% RETURN ON BOOK VALUE: TOTAL CAPITAL	REGULATION: ALLOWED ROE	REGULATION: ORDER DATE
Allegheny Energy, Inc. (NYSE-AYE)	[redacted]	81	[redacted]	2.22	[redacted]	Baa2	[redacted]	18.3	[redacted]	10.46	[redacted]
American Electric Power Co. (NYSE-AEP)	[redacted]	89	[redacted]	2.22	[redacted]	Baa1	[redacted]	14.9	[redacted]	10.81	[redacted]
Central Vermont Public Serv. Corp. (NYSE-CV)	[redacted]	100	[redacted]	0.97	[redacted]	NR	[redacted]	7.4	[redacted]	10.71	[redacted]
Cleco Corporation (NYSE-CNL)	[redacted]	96	[redacted]	1.76	[redacted]	Baa1	[redacted]	16.8	[redacted]	11.25	[redacted]
DPL Inc.(NYSE-DPL)	[redacted]	100	[redacted]	1.80	[redacted]	A2	[redacted]	NM	[redacted]	11.00	[redacted]
Edison International (NYSE-EIX)	[redacted]	80	[redacted]	1.33	[redacted]	A2	[redacted]	12.7	[redacted]	11.60	[redacted]
El Paso Electric Company (ASE-EE)	[redacted]	98	[redacted]	1.60	[redacted]	Baa2	[redacted]	11.8	[redacted]	11.25	[redacted]
FirstEnergy Corporation (NYSE-FE)	[redacted]	88	[redacted]	1.21	[redacted]	Baa2	[redacted]	15.0	[redacted]	9.75	[redacted]
FPL Group, Inc. (NYSE-FPL)	[redacted]	75	[redacted]	1.89	[redacted]	Aa3	[redacted]	13.8	[redacted]	11.75	[redacted]
Great Plains Energy Incorporated (NYSE-GXP)	[redacted]	39	[redacted]	1.05	[redacted]	A3	[redacted]	11.4	[redacted]	10.45	[redacted]
Hawaiian Electric Industries, Inc. (NYSE-HE)	[redacted]	81	[redacted]	0.91	[redacted]	Baa2	[redacted]	9.3	[redacted]	10.82	[redacted]
IDACORP, Inc. (NYSE-IDA)	[redacted]	100	[redacted]	2.99	[redacted]	A3	[redacted]	6.7	[redacted]	-	[redacted]
Maine & Maritimes Corporation (ASE-MAM)	[redacted]	100	[redacted]	1.65	[redacted]	NR	[redacted]	4.7	[redacted]	10.20	[redacted]
OGE Energy Corp. (NYSE-OGE)	[redacted]	48	[redacted]	1.11	[redacted]	Baa1	[redacted]	14.7	[redacted]	10.38	[redacted]
Otter Tail Corporation (NDQ-OTTR)	[redacted]	27	[redacted]	0.71	[redacted]	A3	[redacted]	10.0	[redacted]	12.00	[redacted]
Pinnacle West Capital Corp. (NYSE-PNW)	[redacted]	84	[redacted]	2.37	[redacted]	Baa2	[redacted]	8.0	[redacted]	10.75	[redacted]
Portland General Electric (NYSE-POR)	[redacted]	99	[redacted]	1.77	[redacted]	Baa1	[redacted]	4.9	[redacted]	10.80	[redacted]
Progress Energy Inc. (NYSE-PGN)	[redacted]	100	[redacted]	1.91	[redacted]	A2	[redacted]	7.3	[redacted]	12.42	[redacted]
Southern Company (NYSE-SO)	[redacted]	99	[redacted]	2.18	[redacted]	A2	[redacted]	14.2	[redacted]	11.93	[redacted]
UIL Holdings Corporation (NYSE-UIL)	[redacted]	100	[redacted]	0.98	[redacted]	Baa2	[redacted]	10.1	[redacted]	9.75	[redacted]
Westar Energy, Inc. (NYSE-WR)	[redacted]	69	[redacted]	2.80	[redacted]	Baa2	[redacted]	11.3	[redacted]	10.00	[redacted]
AVERAGE	[redacted]		[redacted]		[redacted]		[redacted]	11.2	[redacted]	10.90	[redacted]

11

COMBINATION ELECTRIC & GAS COMPANIES

COMPANY	TOTAL REV $ MILL (1)	% REG ELEC REV	NET PLANT $ MILL	NET PLANT PER $ REV (1)	S&P BOND RATING	MOODY'S BOND RATING	COMMON EQUITY RATIO (3)	% RETURN ON BOOK VALUE COMMON EQUITY (4)	% RETURN ON BOOK VALUE TOTAL CAPITAL	REGULATION ALLOWED ROE	REGULATION ORDER DATE
AES Corporation (NYSE-AES)	[redacted]	49	[redacted]	1.44	[redacted]	Baa1	[redacted]	0.7	[redacted]	-	[redacted]
ALLETE, Inc. (NYSE-ALE)	[redacted]	87	[redacted]	1.36	[redacted]	NR	[redacted]	13.2	[redacted]	11.60	[redacted]
Alliant Energy Corporation (NYSE-LNT)	[redacted]	69	[redacted]	1.26	[redacted]	A2	[redacted]	16.2	[redacted]	11.02	[redacted]
Ameren Corporation (NYSE-AEE)	[redacted]	83	[redacted]	2.01	[redacted]	Baa2	[redacted]	9.5	[redacted]	10.29	[redacted]
Avista Corporation (NYSE-AVA)	[redacted]	51	[redacted]	1.63	[redacted]	Baa2	[redacted]	5.3	[redacted]	10.35	[redacted]
Black Hills Corporation (NYSE-BKH)	[redacted]	30	[redacted]	2.72	[redacted]	Baa1	[redacted]	8.8	[redacted]	10.75	[redacted]
CenterPoint Energy (NYSE-CNP)	[redacted]	17	[redacted]	0.99	[redacted]	Baa2	[redacted]	22.2	[redacted]	10.17	[redacted]
CH Energy Group, Inc. (NYSE-CHG)	[redacted]	48	[redacted]	0.71	[redacted]	A2	[redacted]	7.7	[redacted]	9.60	[redacted]
CMS Energy Corporation (NYSE-CMS)	[redacted]	54	[redacted]	1.36	[redacted]	Baa1	[redacted]	0.0	[redacted]	10.93	[redacted]
Consolidated Edison, Inc. (NYSE-ED)	[redacted]	62	[redacted]	1.47	[redacted]	A1	[redacted]	11.0	[redacted]	9.73	[redacted]
Constellation Energy Group, Inc. (NYSE-CEG)	[redacted]	13	[redacted]	0.48	[redacted]	Baa2	[redacted]	13.4	[redacted]	11.00	[redacted]
Dominion Resources, Inc. (NYSE-D)	[redacted]	40	[redacted]	1.41	[redacted]	Baa1	[redacted]	NM	[redacted]	10.50	[redacted]
DTE Energy Company (NYSE-DTE)	[redacted]	59	[redacted]	1.38	[redacted]	A3	[redacted]	17.6	[redacted]	11.00	[redacted]
Duke Energy Corporation (NYSE-DUK)	[redacted]	71	[redacted]	2.44	[redacted]	A3	[redacted]	7.7	[redacted]	10.85	[redacted]
Empire District Electric Co. (NYSE-EDE)	[redacted]	87	[redacted]	2.44	[redacted]	Baa1	[redacted]	7.0	[redacted]	10.90	[redacted]
Energy East Corporation (NYSE-EAS)	[redacted]	56	[redacted]	1.17	[redacted]	A3	[redacted]	7.7	[redacted]	10.69	[redacted]
Entergy Corporation (NYSE-ETR)	[redacted]	76	[redacted]	1.80	[redacted]	Baa2	[redacted]	15.8	[redacted]	10.83	[redacted]
Exelon Corporation (NYSE-EXC)	[redacted]	56	[redacted]	1.33	[redacted]	A3	[redacted]	NM	[redacted]	10.05	[redacted]
Florida Public Utilities Company (ASE-FPU)	[redacted]	42	[redacted]	0.98	[redacted]	Aaa	[redacted]	6.9	[redacted]	11.28	[redacted]
Integrys Energy Group (NYSE-TEG)	[redacted]	11	[redacted]	0.39	[redacted]	A1	[redacted]	8.3	[redacted]	11.03	[redacted]
MDU Resources Group, Inc. (NYSE-MDU)	[redacted]	4	[redacted]	0.86	[redacted]	A2	[redacted]	15.6	[redacted]	11.31	[redacted]
MGE Energy, Inc. (NDQ-MGEE)	[redacted]	61	[redacted]	1.25	[redacted]	Aa2	[redacted]	11.4	[redacted]	10.80	[redacted]
NiSource Inc. (NYSE-NI)	[redacted]	16	[redacted]	1.16	[redacted]	Baa2	[redacted]	5.7	[redacted]	11.33	[redacted]
Northeast Utilities (NYSE-NU)	[redacted]	84	[redacted]	1.32	[redacted]	Baa1	[redacted]	7.9	[redacted]	9.72	[redacted]
Northwestern Corporation (NYSE-NWE)	[redacted]	62	[redacted]	1.46	[redacted]	Baa3	[redacted]	7.2	[redacted]	11.11	[redacted]
NSTAR (NYSE-NST)	[redacted]	78	[redacted]	1.32	[redacted]	A1	[redacted]	7.4	[redacted]	12.50	[redacted]
Pepco Holdings, Inc. (NYSE-POM)	[redacted]	56	[redacted]	0.81	[redacted]	Baa1	[redacted]	9.5	[redacted]	10.15	[redacted]
PG&E Corporation (NYSE-PCG)	[redacted]	72	[redacted]	1.78	[redacted]	A3	[redacted]	11.7	[redacted]	11.35	[redacted]
PNM Resources, Inc. (NYSE-PNM)	[redacted]	100	[redacted]	1.83	[redacted]	Baa3	[redacted]	NM	[redacted]	10.28	[redacted]
PPL Corporation (NYSE-PPL)	[redacted]	62	[redacted]	1.94	[redacted]	A3	[redacted]	19.4	[redacted]	9.57	[redacted]
Public Service Enterprise Group (NYSE-PEG)	[redacted]	66	[redacted]	1.03	[redacted]	A3	[redacted]	20.3	[redacted]	9.88	[redacted]
Puget Energy, Inc. (NYSE-PSD)	[redacted]	64	[redacted]	1.74	[redacted]	Baa2	[redacted]	7.7	[redacted]	10.40	[redacted]
SCANA Corporation (NYSE-SCG)	[redacted]	42	[redacted]	1.60	[redacted]	A2	[redacted]	11.5	[redacted]	10.93	[redacted]
SEMPRA Energy (NYSE-SRE)	[redacted]	29	[redacted]	1.31	[redacted]	A1	[redacted]	14.1	[redacted]	10.70	[redacted]
Sierra Pacific Resources (NYSE-SRP)	[redacted]	94	[redacted]	1.96	[redacted]	Baa3	[redacted]	7.0	[redacted]	10.48	[redacted]
TECO Energy, Inc. (NYSE-TE)	[redacted]	62	[redacted]	1.41	[redacted]	Baa2	[redacted]	19.9	[redacted]	11.25	[redacted]
UniSource Energy Corporation (NYSE-UNS)	[redacted]	85	[redacted]	1.75	[redacted]	Baa2	[redacted]	7.6	[redacted]	10.34	[redacted]
Unitil Corporation (ASE-UTL)	[redacted]	85	[redacted]	0.97	[redacted]	NR	[redacted]	9.5	[redacted]	9.93	[redacted]
Vectren Corporation (NYSE-VVC)	[redacted]	22	[redacted]	1.09	[redacted]	A3	[redacted]	11.0	[redacted]	10.43	[redacted]
Wisconsin Energy Corporation (NYSE-WEC)	[redacted]	62	[redacted]	1.81	[redacted]	Aa3	[redacted]	11.7	[redacted]	10.75	[redacted]
Xcel Energy Inc. (NYSE-XEL)	[redacted]	78	[redacted]	1.65	[redacted]	A3	[redacted]	9.9	[redacted]	10.83	[redacted]
AVERAGE	[redacted]		[redacted]		[redacted]		[redacted]	10.7	[redacted]	10.66	[redacted]
COMBINED ELECTRIC/COMBINATION ELECTRIC & GAS AVERAGES					[redacted]		[redacted]	10.8	[redacted]	10.74	[redacted]

Moody's Investors Service

Global Credit Research
Rating Action
25 JUL 2008

Rating Action: Arizona Public Service Company

Moody's revises outlook of Pinnacle West and Arizona Public Service to stable

Approximately $3 billion of debt securities affected

New York, July 25, 2008 -- Moody's Investors Service changed the rating outlooks of Pinnacle West Capital Corporation (Pinnacle, Baa3 senior unsecured) and its subsidiaries, Arizona Public Service Company (APS, Baa2 senior unsecured) and PVNGS II Funding Corp. Inc. (PVNGS II: Baa2, senior secured lease obligation bonds) to stable from negative.

The stable outlook considers the companies' improving regulatory environment and operating performance with financial results that are expected to remain consistently within the range expected for integrated utilities rated Baa. APS has begun to receive more supportive regulatory decisions, including "new connection" fees allowing faster recovery for new hookups plus a transmission cost adjustor and power supply adjustor which has limited APS' exposure to fuel and purchased power fluctuations. In addition, performance at the Palo Verde nuclear power plant has improved and APS is making progress in identifying and improving the safety and communication issues at the plant.

As a result of some improved timing on cost recoveries, Moody's now expects APS and Pinnacle's cash flow credit metrics to remain at levels comparable to those achieved in 2006 and 2007. This would place the utility and parent in the mid-to-upper range of ratios for electric utilities with medium business risk according to Moody's rating methodology for global regulated electric utilities. For the twelve months ended March 31, 2008, APS' cash from operations pre-working capital (CFO pre-WC) interest coverage was 4.4x and CFO pre-WC to debt was 19.6% which was comparable to year-end 2006 and slightly above the 18.3% and 4.2x metrics registered in 2007. Pinnacle's CFO pre-WC interest coverage of 4.0x and CFO pre-WC to Debt of 17.5% for the twelve months ended March 31, 2008 were modestly below 2006 levels but comparable to 2007 levels where they still remain within the middle of the range for Baa rated electric utilities. We expect these metrics to remain roughly within this range going forward.

The stable outlook also is predicated on an expectation for continued improvement at Palo Verde such that current heightened regulatory scrutiny is reduced to normal levels over the medium term and that more balanced regulatory relief continues especially given that APS has several rate filings currently pending. We also expect Pinnacle to continue to finance APS' capital expenditures in a manner consistent with its investment-grade rating.

Pinnacle West Capital Corporation, headquartered in Phoenix, Arizona, provides electric service to a substantial portion of the state of Arizona, sells energy-related products and services, and develops residential, commercial and industrial real estate. Pinnacle conducts its business through its subsidiaries. Wholly-owned Arizona Public Service Company is its principal subsidiary.

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June 25, 2008

Arizona Public Service Co.

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Table Of Contents

Arizona Public Service Co.

Major Rating Factors

Corporate Credit Rating

BBB-/Stable/A-3

Strengths:

- A favorable power supply adjuster (PSA) that while capped at 4 mils per kilowatt-hour (kWh) is benched to projected power prices, which should minimize fuel and purchased power deferral balances going forward;
- Declining legacy deferral balances, reflecting the recovery through surcharges of past fuel and purchased power costs from retail ratepayers;
- An attractive service territory, which while currently weakened by a real estate cycle that is depressing new customer connections, nevertheless is expected to experience above-average growth over the long run;
- A balance power supply portfolio that is a mixture of coal, nuclear, and gas generation and purchases; due to a self-build moratorium in place until 2015, Arizona Public Service (APS) is expected to increasingly rely on gas-fired purchases, which underlines the importance of a strong PSA;
- Stabilized operations at Palo Verde, although the nuclear units remain under heightened Nuclear Regulatory Commission (NRC) scrutiny; APS operates the plant and owns a 29.1% share of the plant; and
- A manageable maturity schedule for both the parent and the utility until 2011 when about $578 million is due on a consolidated basis.

Weaknesses:

- The consolidated financial profile of the company is unlikely to meaningfully improve for the foreseeable future due to APS' heavy capital investment, coupled with a lagged regulatory process in Arizona;
- Continued tension in the relationship between APS and the Arizona Corporation Commission (ACC), which is particularly unfavorable for credit quality due to the company's ongoing need for rate relief;
- APS' re-filing of its 2008 general rate case based on a revised test year is expected to delay rate relief past the summer of 2009, which will, all else equal, weaken cash flow measures;
- Consolidated free operating cash flows are expected to be negative through at least 2010, based on the company's capital spending program; and
- SunCor's near-term prospects to make distributions to its parent are limited, due a depressed real estate cycle, which has hit the southwest especially hard.

Rationale

Standard & Poor's Ratings Services today affirmed the 'BBB-' corporate credit rating assigned to Pinnacle West Capital Corporation (PWCC) and its utility, Arizona Public Service. The outlook is stable. The consolidated credit ratings of PWCC primarily reflect the operations of its largest subsidiary, APS, a regulated, electric utility serving about 1.1 million customers within its service territory, which spans roughly two-thirds of Arizona and includes about half of the Phoenix MSA. We view the business profile of PWCC and APS to be 'strong'. While the company continues to benefit from a number of favorable attributes including a good service territory, a reasonably balanced

power supply portfolio and a good PSA. However, APS' continues to face significant regulatory challenges.

APS provided the company with about 92% of its consolidated net income in 2007. SunCor, PWCC's real estate development company, provided about 4%, but due to the significant real estate slowdown in the southwest, it is unlikely it will be a meaningful contributor of cash flows or income over the next several years. (Prior to the real estate downturn, our forecasts have conservatively limited earnings from this subsidiary due to the cyclic nature of its cash flows.) Other subsidiary operations include Pinnacle West Trading and Marketing, which contributed about 4% of consolidated net income in 2007. This subsidiary has since last year been minimizing trading operations. Its largest contract was serving all-requirements load for UNS Electric Inc., which ended in May 2008.

We view the financial profile of PWCC and APS to be 'aggressive', which reflects: year-end debt to total capitalization of 57% (adjusted for items such as power purchases and operating leases); heavy capital spending that is expected to drive negative free operating cash flow for the foreseeable future; cash flow weakness as a function of protracted rate cases; and, while modest, the presence of unregulated activities, which can be unpredictable in their earnings contributions.

Because the preponderance of cash flows for consolidated operations stems from APS, we expect financial performance will continue to be heavily dependent on regulatory outcomes. The conclusion of APS' last general rate case in June 2007 (filed in November 2005 and revised in early 2006) provided the company with mechanisms to recover legacy deferrals and speed the recovery of fuel costs going forward. This rate relief, in place for the last half of 2007, assisted the company in maintaining credit metrics roughly in line with past performance. Funds from operations (FFO) to total debt was about 16% at year-end, with FFO interest coverage around 4x. On a trailing 12-month basis the company's performance has been slightly above these levels, due in part to the federal tax stimulus package approved by the U.S. Congress earlier this year, which is expected to increase deferred taxes (which are added back to FFO and thus increase this total).

We expect APS to be in more or less continuous rate case mode for the next few years. Given APS' capital spending program, forecasted to be about $1.1 billion annually through 2010, the utility will need to file regular general rate cases to manage recovery of its investment. The use of a historical test year in Arizona, coupled with the fact that fully litigated rate cases take between 18 to 24 months to complete, is expected to result in no meaningful improvement in financial performance through 2009 and possibly beyond, depending on the timing and the outcome of the company's current case.

APS filed its current rate case in March 2008. ACC staff requested that the company revise its filing to reflect a test year ending Dec. 31, 2007 (as opposed to the originally filed version based on a Sept. 30, 2007, test year). The revised case has not been officially certified by the ACC, but certification is expected by July 2. Unlike the company's last rate case, in which $315 million of the $322 million of rate relief granted was for fuel and power-related costs, the majority of the current case is for nonfuel expenditures.

While the revised case increased the company's request to $278 million (about an 8.5% increase, excluding the company's request that customers be assessed about $53 million in impact fees), the re-filing means that is unlikely the ACC will reach an outcome in the case before October 2009, and because the majority of APS' sales occur in the summer months, the company's financial performance could weaken in 2009.

This month, the company requested that the ACC allow it to continue to collect a $0.004/kWh charge that it has been collecting in 2007 to recover legacy purchased power and fuel deferrals. Given that the portion of deferred

costs associated with this surcharge is due to be paid by July or August, APS has asked that the ACC continue the charge, but authorize collection as an interim base rate increase, subject to refund as part of the resolution of its rate case, expected in fall 2009. (Last year, the ACC approved similar relief for Tucson Electric Power in its pending rate case settlement when it granted the southern Arizona utility the opportunity to continue to collect charges related to a competitive transition charge, or CTC, while its rate case is pending.) While retail customers would essentially see no rate increase because APS is asking to continue the surcharge as an interim increase, it is unclear what action the ACC will take. A vote could occur as early as late summer.

In 2008, we expect a procedural schedule to be established for the APS rate case, and greater clarity around the timing of an outcome will be available once this is issued. Of note is that three of the five commissioners are facing term limits and will no longer be on the ACC beginning in 2009.. Commissioners are popularly elected and about a dozen candidates have announced they will run for the November election. As a result, a majority of the commissioners presiding now will not be on the commission when an APS rate case ruling is rendered. What this means for credit quality is unclear.

APS was successful earlier this year in receiving approval for a change in its line extension policies, which eliminates the free footage allowance that used to be available for customers. As a result, the portion of the company's capital expenditures associated with new line extensions will be offset with contributions in aid of construction (CIAC). This is favorable and year to date ended March 31, 2008, had added about $10 million in incremental cash flows to the company. Because it is booked under investing activities, cash flow metrics are not improved, but we recognize the significant benefit of APS receiving upfront cash from customers to meet a portion of its distribution capital investment plans. Future cash flows from customers in the form of CIAC will depend on the number of new meter sets, which are significantly off year to date due to the poor real estate market in Arizona and a slowing economy generally.

APS has a well-diversified power supply portfolio that in 2007 consisted of about 22% nuclear generation, 37% coal generation, approximately 18% owned gas generation, and the balance, about 23%, of purchases. We would expect the company's purchased power obligations to steadily climb due to the fact that APS is under a self build moratorium until 2015. APS will also need to meet relatively stringent renewable portfolio standards (RPS). It has in place a surcharge to pass through to customers the costs of RPS compliance.

Palo Verde performance has stabilized, and it has a plan in place to address NRC concerns. As of the first quarter of 2008, the combined capacity factors for all three Palo Verde units was 93%, as compared with 79% for 2007 (which reflects in part an extended planned outage to replace steam generators at unit 3) and 71% in 2006, which largely reflects unplanned outages at unit 1 related to excessive vibration that occurred when that unit exited its extended outage for refueling and replacement of steam generators. Palo Verde Unit 3 remains in the NRC's "multiple/repetitive degraded cornerstone" column of the NRC's Action matrix, which subjects all three Palo Verde units to enhanced NRC inspection regime. Preliminary work in support of this took place throughout the summer of 2007. In February, the NRC issued its inspection report, which determined the plant was operating safely but which also outlined an improvement plan for APS. In late March, APS in turn submitted to the NRC a final improvement plant addressing issues raised in the NRC inspection report. While the nuclear units appear to be on a path to improve operational performance and restore NRC confidence in the operational and safety standards at the plant, this will remain an area of concern until the NRC removes it degraded designation.

Short-term credit factors

APS and PWCC's short-term rating is 'A-3'. Liquidity is adequate. Pinnacle West has $18 million of cash and cash equivalents, and total credit facilities of nearly $1.4 billion, with approximately $943 million available as of March 31, 2008. In October 2007, APS received approval from ACC to increase its authorized short-term debt borrowing capacity by $500 million, and long-term debt borrowing capacity by $1 billion. This will help address the needs of its growing customer base, and the increasing requirement for natural gas and purchased power.

Pinnacle West had close to $185 million available under its $300 million unsecured revolving credit facility that expires in December 2010. APS had $682 million available under its two unsecured revolving credit facilities, $400 million of which expires in December 2010, and $500 million in September 2011. SunCor has two credit facilities expiring in October and December 2008 that total $170 million and approximately $76 million, respectively, available as of September 2007.

Discretionary cash flow is expected to be negative for 2008 due to APS' capital expenditure plans. Excluding the remarketing of APS' pollution control debt, neither PWCC nor APS has any significant debt obligations maturing until 2011.

Outlook

The stable outlook reflects our expectation that consolidated cash flow volatility has been tamped down by the ACC's approval of a stronger PSA that speeds the recovery of fuel costs, but consolidated financial performance will continue to be challenged by regulatory lag at APS, which could be moderated by APS' pending interim rate request. The stable outlook is premised on no meaningful adverse changes in the company's business risks and continued financial performance that is not significantly weaker than 2007 results. Equity issuances will be expected to balance the capital structure of the company as APS continues to invest heavily in infrastructure. Ratings could be lowered to speculative grade if the company is not able to overcome the challenge of ensuring timely recovery of its prudently incurred costs through rate increases approved by the ACC. Given these challenges, and that presented by NRC scrutiny of Palo Verde, we see little potential for positive movement in the ratings or outlook.

Rating Methodology

The ratings on PWCC and its subsidiaries are determined based on Standard & Poor's consolidated ratings methodology. The application of this approach reflects significant financial and operational inter-relationships among the rated entities and captures the relative contribution to business risk and cash flow of the operating segments. In the absence of meaningful regulatory measures that can restrict the flow of funds within the company, Standard & Poor's considers PWCC's consolidated financial profile, while still analyzing the financial profiles of the standalone entities, to be the best indicator of credit quality of the parent and its subsidiaries, including APS.

Accounting

PWCC reports its financial statements in accordance with U.S. GAAP. These statements received an unqualified opinion by PWCC's independent auditor, Deloitte and Touche LLC, in the most recent annual audited period.

The company benefits from the use of regulatory accounting SFAS 71 (accounting for the effects of certain types of

regulation), under which some incurred costs or benefits that will probably be recovered or refunded in customer rates are deferred and recorded as regulatory assets or liabilities. As of Dec. 31, 2007, PWCC's consolidated balance sheet contained total regulatory assets and total regulatory liabilities of $625 million and $643 million respectively, reflecting assets expected to be recovered and liabilities expected to be settled in future rates.

We make several adjustments to PWCC's financial statements. In 1986, APS sold about 42% of Palo Verde Unit 2 as part of a sale-leaseback transaction. We treat these obligations as operating leases and in 2007 imputed an off-balance-sheet obligation of $432.18 million. We also impute $293 million for power purchase obligations in 2007, a number we expect to increase given APS' increasing power purchases. Reported ratios also reflect adjustments to impute debt for unfunded pension and postretirement benefit obligations of $329.72 million as of the end of 2007.

Table 1

Pinnacle West Capital Corp. -- Peer Comparison*

Industry Sector: Electric

	Pinnacle West Capital Corp.	Puget Energy Inc.	Avista Corp.	Unisource Energy Corp.	PNM Resources Inc.
Rating as of June 24, 2008	BBB-/Stable/A-3	BBB-/Watch Neg/--	BBB-/Stable/A-3	-/-/-	BB-/Stable/B-2
	--Average of past three fiscal years--				
(Mil. $)					
Revenues	3,304.4	2,899.7	1,427.9	1,309.3	2,154.2
Net income from cont. oper.	264.1	166.1	52.3	57.9	82.8
Funds from operations (FFO)	683.7	442.5	186.2	283.6	281.5
Capital expenditures	778.6	726.5	194.5	225.1	339.1
Cash and short-term investments	99.2	30.1	20.6	113.1	70.4
Debt	4,419.9	3,343.9	1,368.8	1,838.8	2,684.7
Preferred stock	0.0	89.5	0.0	0.0	9.6
Equity	3,366.1	2,298.5	854.7	640.2	1,564.5
Debt and equity	7,786.0	5,642.4	2,223.5	2,479.0	4,249.3
Adjusted ratios					
EBIT interest coverage (x)	2.8	2.0	1.8	1.7	1.7
FFO int. cov. (X)	3.6	2.9	2.7	2.8	2.7
FFO/debt (%)	15.5	13.2	13.6	15.4	10.5
Discretionary cash flow/debt (%)	(8.2)	(13.4)	(1.7)	2.1	(5.7)
Net cash flow / capex (%)	62.2	46.9	81.0	113.0	65.2
Total debt/debt plus equity (%)	56.8	59.3	61.6	74.2	63.2
Return on common equity (%)	6.8	7.2	5.7	8.3	5.4
Common dividend payout ratio (un-adj.) (%)	75.5	60.4	54.7	50.4	72.9

*Fully adjusted (including postretirement obligations).

Table 2

Pinnacle West Capital Corp. -- Financial Summary*

Industry Sector: Electric

	--Fiscal year ended Dec. 31--				
	2007	**2006**	**2005**	**2004**	**2003**
Rating history	BBB-/Stable/A-3	BBB-/Stable/A-3	BBB-/Stable/A-3	BBB/Negative/A-2	BBB/Stable/A-2
(Mil. $)					
Revenues	3,523.6	3,401.7	2,988.0	2,899.7	2,759.5
Net income from continuing operations	298.8	317.1	176.3	243.2	240.6
Funds from operations (FFO)	735.3	736.3	579.6	567.6	932.3
Capital expenditures	933.9	743.2	658.7	591.7	713.3
Cash and short-term investments	56.3	87.2	154.0	163.4	131.1
Debt	4,686.5	4,358.6	4,214.6	4,272.8	4,120.9
Preferred stock	0.0	0.0	0.0	0.0	0.0
Equity	3,531.6	3,446.1	3,120.5	2,653.7	2,510.0
Debt and equity	8,218.1	7,804.7	7,335.1	6,926.5	6,630.8
Adjusted ratios					
EBIT interest coverage (x)	2.7	3.0	2.6	2.6	2.2
FFO int. cov. (x)	3.7	3.8	3.3	3.2	4.2
FFO/debt (%)	15.7	16.9	13.8	13.3	22.6
Discretionary cash flow/debt (%)	(10.1)	(12.5)	(1.7)	2.6	1.0
Net cash flow / capex (%)	56.2	72.0	59.7	67.7	108.6
Debt/debt and equity (%)	57.0	55.8	57.5	61.7	62.1
Return on common equity (%)	7.3	8.2	4.8	7.7	7.1
Common dividend payout ratio (un-adj.) (%)	70.4	63.4	105.9	68.6	65.4

*Fully adjusted (including postretirement obligations).

Table 3

Reconciliation Of Pinnacle West Capital Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*

	--Fiscal year ended Dec. 31, 2007--							
Pinnacle West Capital Corp. reported amounts								
	Debt	**Operating income (before D&A)**	**Operating income (before D&A)**	**Operating income (after D&A)**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Capital expenditures**
Reported	3,631.6	992.7	992.7	619.3	189.6	649.6	649.6	941.6
Standard & Poor's adjustments								
Operating leases	432.2	79.0	27.7	27.7	27.7	51.3	51.3	15.4
Postretirement benefit obligations	329.7	12.8	12.8	12.8	--	8.7	8.7	--
Capitalized interest	--	--	--	--	23.1	(23.1)	(23.1)	(23.1)
Share-based compensation expense	--	--	6.0	--	--	--	--	--
Power purchase agreements	293.0	21.1	21.1	18.1	18.1	3.0	3.0	--

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Table 3

Reconciliation Of Pinnacle West Capital Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*(cont.)

Reclassification of nonoperating income (expenses)	--	--	--	20.0	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	66.6	--
US decommissioning fund contributions	--	--	--	--	--	(20.7)	(20.7)	--
Total adjustments	1,054.9	112.8	67.6	78.6	68.9	19.2	85.8	(7.7)

Standard & Poor's adjusted amounts

	Debt	Operating income (before D&A)	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Capital expenditures
Adjusted	4,686.5	1,105.5	1,060.2	697.8	258.4	668.8	735.3	933.9

*Pinnacle West Capital Corp. reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts.

Ratings Detail (As Of June 25, 2008)*

Arizona Public Service Co.	
Corporate Credit Rating	BBB-/Stable/A-3
Commercial Paper	
Local Currency	A-3
Senior Unsecured	
Local Currency	BBB-
Corporate Credit Ratings History	
21-Dec-2005	BBB-/Stable/A-3
01-Apr-2005	BBB/Stable/A-2
19-Mar-2004	BBB/Negative/A-2
Related Entities	
Pinnacle West Capital Corp.	
Issuer Credit Rating	BBB-/Stable/A-3
Commercial Paper	
Local Currency	A-3
Senior Unsecured	
Local Currency	BB+
PVNGS II Funding Corp. Inc.	
Issuer Credit Rating	BBB-/Stable/--
Senior Unsecured	
Local Currency	BBB-

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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Issuer Ranking: U.S. Regulated Electric Utilities, Strongest To Weakest

Publication date: 02-Jun-2008
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The U.S. electric utility industry withstood a turbulent first quarter of 2008. Strong liquidity positions for the sector as a whole enabled the companies to deal with the fallout from auction rate securities and insured deals in a credit-neutral manner. Debt issuance of nearly $10 billion in the quarter benefited from falling interest rates.

The following list contains Standard & Poor's Ratings Services' ratings, outlooks, and business and financial profiles for companies with a primary regulated electric focus. This list reflects the current ratings and outlooks as of June 2, 2008. The rankings in each rating/outlook grouping (e.g., BBB+/Stable/--) are based on relative business risk.

A Standard & Poor's rating outlook assesses the potential direction of an issuer's long-term debt rating over the intermediate to longer term. In determining a rating outlook, consideration is given to any changes in the economic and/or fundamental business conditions. An outlook is not necessarily a precursor of a rating change or future CreditWatch action. "Positive" indicates that a rating may be raised; "negative" means a rating may be lowered; "stable" indicates that ratings are not likely to change; and "developing" means ratings may be raised or lowered.

Utility business profiles can be categorized as "Excellent," "Strong," "Satisfactory," "Weak," or "Vulnerable" under the credit ratings methodology applied to all rated corporate entities at Standard & Poor's. To determine a utility's business profile, Standard & Poor's analyzes the following qualitative business or operating characteristics: markets and service area economy; competitive position; fuel and power supply; operations; asset concentration; regulation; and management. Issuer credit ratings, shown as long-term rating/outlook or CreditWatch/short-term rating, are local and foreign currency unless otherwise noted. A dash (--) indicates not rated.

For the related industry report card, please see "Industry Report Card: U.S. Electric Utility Sector Continues To Benefit From Strong Liquidity Amid Current Credit Crunch," published March 27, 2008.

Download Table

U.S. Regulated Electric Utilities

As of June 2, 2008

Company	Corporate credit rating	Business profile	Financial profile
Madison Gas & Electric Co.	AA-/Stable/A-1+	Excellent	Modest
American Transmission Co.	A+/Stable/A-1	Excellent	Intermediate
Midwest Independent Transmission System Operator Inc.	A+/Stable/--	Excellent	Intermediate

NSTAR Electric Co.	A+/Stable/A-1	Excellent	Intermediate
NSTAR Gas Co.	A+/Stable/--	Excellent	Intermediate
NSTAR	A+/Stable/A-1	Excellent	Intermediate
Florida Power & Light Co.	A/Stable/A-1	Excellent	Intermediate
KeySpan Energy Delivery Long Island	A/Stable/A-1	Excellent	Intermediate
KeySpan Energy Delivery New York	A/Stable/A-1	Excellent	Intermediate
Northern Natural Gas Co.	A/Stable/--	Excellent	Intermediate
Alabama Power Co.	A/Stable/A-1	Excellent	Intermediate
Georgia Power Co.	A/Stable/A-1	Excellent	Intermediate
Mississippi Power Co.	A/Stable/A-1	Excellent	Intermediate
Gulf Power Co.	A/Stable/--	Excellent	Intermediate
San Diego Gas & Electric Co.	A/Stable/--	Excellent	Intermediate
Wisconsin Public Service Corp.	A/Stable/A-2	Excellent	Intermediate
FPL Group Inc.	A/Stable/--	Excellent	Intermediate
Southern Co.	A/Stable/A-1	Excellent	Intermediate
Central Hudson Gas & Electric Corp.	A/Stable/--	Excellent	Intermediate
California Independent System Operator Corp.	A-/Stable/--	Excellent	Intermediate
Massachusetts Electric Co.	A-/Stable/A-2	Excellent	Intermediate
Narragansett Electric Co.	A-/Stable/A-2	Excellent	Intermediate
New England Power Co.	A-/Stable/A-2	Excellent	Intermediate
Consolidated Edison Co. of New York Inc.	A-/Stable/A-2	Excellent	Intermediate
Orange and Rockland Utilities Inc.	A-/Stable/A-2	Excellent	Intermediate
Rockland Electric Co.	A-/Stable/--	Excellent	Intermediate
Consolidated Edison Inc.	A-/Stable/A-2	Excellent	Intermediate
Wisconsin Gas LLC	A-/Stable/A-2	Excellent	Intermediate
Peoples Gas Light & Coke Co. (The)	A-/Stable/A-2	Excellent	Intermediate
North Shore Gas Co.	A-/Stable/--	Excellent	Intermediate
Peoples Energy Corp.	A-/Stable/A-2	Excellent	Intermediate
Virginia Electric & Power Co.	A-/Stable/A-2	Excellent	Aggressive
Duke Energy Indiana Inc.	A-/Stable/A-2	Excellent	Intermediate

Duke Energy Carolinas LLC	A-/Stable/A-2	Excellent	Intermediate
Duke Energy Ohio Inc.	A-/Stable/A-2	Excellent	Intermediate
Duke Energy Kentucky Inc.	A-/Stable/--	Excellent	Intermediate
Wisconsin Electric Power Co.	A-/Stable/A-2	Excellent	Intermediate
Northern States Power Wisconsin	A-/Stable/--	Excellent	Intermediate
Wisconsin Power & Light Co.	A-/Stable/A-2	Excellent	Intermediate
Southern Indiana Gas & Electric Co.	A-/Stable/--	Excellent	Intermediate
MidAmerican Energy Holdings Co.	A-/Stable/--	Excellent	Aggressive
PPL Electric Utilities Corp.	A-/Stable/A-2	Excellent	Aggressive
Niagara Mohawk Power Corp.	A-/Stable/A-2	Excellent	Aggressive
PacifiCorp	A-/Stable/A-1	Excellent	Aggressive
Cinergy Corp.	A-/Stable/A-2	Excellent	Intermediate
Duke Energy Corp.	A-/Stable/A-2	Excellent	Intermediate
MidAmerican Energy Co.	A-/Stable/A-1	Excellent	Aggressive
National Grid USA	A-/Stable/A-2	Excellent	Intermediate
Dominion Resources Inc.	A-/Stable/A-2	Excellent	Aggressive
Integrys Energy Group Inc.	A-/Stable/A-2	Strong	Intermediate
-			
Public Service Co. of North Carolina Inc.	A-/Negative/A-2	Excellent	Aggressive
South Carolina Electric & Gas Co.	A-/Negative/A-2	Excellent	Aggressive
SCANA Corp.	A-/Negative/--	Excellent	Aggressive
-			
Southern California Edison Co.	BBB+/Stable/A-2	Excellent	Intermediate
Pacific Gas & Electric Co.	BBB+/Stable/A-2	Excellent	Intermediate
Florida Power Corp. d/b/a Progress Energy Florida Inc.	BBB+/Stable/A-2	Excellent	Aggressive
Carolina Power & Light Co. d/b/a Progress Energy Carolinas Inc.	BBB+/Stable/A-2	Excellent	Aggressive
Public Service Co. of Colorado	BBB+/Stable/A-2	Excellent	Aggressive
Northern States Power Co.	BBB+/Stable/A-2	Excellent	Aggressive
PECO Energy Co.	BBB+/Stable/A-2	Excellent	Aggressive
Southwestern Public Service Co.	BBB+/Stable/A-2	Excellent	Aggressive
Interstate Power & Light Co.	BBB+/Stable/A-2	Excellent	Aggressive
Wisconsin Energy Corp.	BBB+/Stable/A-2	Excellent	Aggressive

Xcel Energy Inc.	BBB+/Stable/A-2	Excellent	Aggressive
Kentucky Utilities Co.	BBB+/Stable/A-2	Excellent	Intermediate
Louisville Gas & Electric Co.	BBB+/Stable/--	Excellent	Intermediate
Progress Energy Inc.	BBB+/Stable/A-2	Excellent	Aggressive
Alliant Energy Corp.	BBB+/Stable/A-2	Excellent	Aggressive
E.ON U.S. LLC	BBB+/Stable/--	Excellent	Intermediate
Oklahoma Gas & Electric Co.	BBB+/Stable/A-2	Excellent	Intermediate
Portland General Electric Co.	BBB+/Stable/A-2	Strong	Intermediate
OGE Energy Corp.	BBB+/Stable/A-2	Strong	Intermediate
ALLETE Inc.	BBB+/Stable/A-2	Strong	Intermediate
Montana-Dakota Utilities Co.	BBB+/Stable/--	Strong	Intermediate
-			
Connecticut Natural Gas Corp.	BBB+/Negative/--	Excellent	Intermediate
Southern Connecticut Gas Co.	BBB+/Negative/--	Excellent	Intermediate
New York State Electric & Gas Corp.	BBB+/Negative/A-2	Excellent	Aggressive
Central Maine Power Co.	BBB+/Negative/--	Excellent	Aggressive
Rochester Gas & Electric Corp.	BBB+/Negative/--	Excellent	Aggressive
Energy East Corp.	BBB+/Negative/A-2	Excellent	Aggressive
Baltimore Gas & Electric Co.	BBB+/Negative/A-2	Strong	Intermediate
Otter Tail Corp.	BBB+/Negative/--	Strong	Intermediate
-			
Enogex Inc.	BBB+/Watch Neg/--	Satisfactory	Intermediate
-			
Dayton Power & Light Co.	BBB/Positive/--	Excellent	Aggressive
DPL Inc.	BBB/Positive/--	Excellent	Aggressive
International Transmission Co.	BBB/Positive/--	Excellent	Aggressive
ITC Holdings Corp.	BBB/Positive/--	Excellent	Aggressive
ITC Midwest LLC	BBB/Positive/--	Excellent	Aggressive
-			
Yankee Gas Services Co.	BBB/Stable/--	Excellent	Aggressive
Michigan Consolidated Gas Co.	BBB/Stable/A-2	Excellent	Aggressive
Public Service Electric & Gas Co.	BBB/Stable/A-2	Excellent	Aggressive
AEP Texas Central Co	BBB/Stable/--	Excellent	Aggressive
AEP Texas North Co	BBB/Stable/--	Excellent	Aggressive

Columbus Southern Power Co.	BBB/Stable/--	Excellent	Aggressive
Ohio Power Co.	BBB/Stable/--	Excellent	Aggressive
Appalachian Power Co.	BBB/Stable/--	Excellent	Aggressive
CenterPoint Energy Houston Electric LLC	BBB/Stable/--	Excellent	Aggressive
CenterPoint Energy Inc.	BBB/Stable/A-2	Excellent	Aggressive
CenterPoint Energy Resources Corp.	BBB/Stable/--	Excellent	Aggressive
Western Massachusetts Electric Co.	BBB/Stable/--	Excellent	Aggressive
Atlantic City Electric Co.	BBB/Stable/A-2	Excellent	Aggressive
Potomac Electric Power Co.	BBB/Stable/A-2	Excellent	Aggressive
Delmarva Power & Light Co.	BBB/Stable/A-2	Excellent	Aggressive
Green Mountain Power Corp.	BBB/Stable/--	Excellent	Aggressive
Kentucky Power Co.	BBB/Stable/--	Excellent	Aggressive
Public Service Co. of Oklahoma	BBB/Stable/--	Excellent	Aggressive
Southwestern Electric Power Co.	BBB/Stable/--	Excellent	Aggressive
Connecticut Light & Power Co.	BBB/Stable/--	Excellent	Aggressive
Public Service Co. of New Hampshire	BBB/Stable/--	Excellent	Aggressive
Detroit Edison Co.	BBB/Stable/A-2	Excellent	Aggressive
American Electric Power Co. Inc.	BBB/Stable/A-2	Excellent	Aggressive
Northeast Utilities	BBB/Stable/--	Excellent	Aggressive
DTE Energy Co.	BBB/Stable/A-2	Excellent	Aggressive
NorthWestern Corp.	BBB/Stable/--	Excellent	Aggressive
Indiana Michigan Power Co.	BBB/Stable/--	Strong	Aggressive
Cleco Power LLC	BBB/Stable/--	Strong	Aggressive
Cleco Corp.	BBB/Stable/--	Strong	Aggressive
Hawaiian Electric Co. Inc.	BBB/Stable/A-2	Strong	Aggressive
Idaho Power Co.	BBB/Stable/A-2	Strong	Aggressive
IDACORP Inc.	BBB/Stable/A-2	Strong	Aggressive
El Paso Electric Co.	BBB/Stable/--	Strong	Aggressive
PEPCO Holdings Inc.	BBB/Stable/A-2	Strong	Aggressive
Hawaiian Electric Industries Inc.	BBB/Stable/A-2	Strong	Aggressive
Entergy Arkansas Inc.	BBB/Negative/--	Strong	Aggressive
Entergy Louisiana LLC	BBB/Negative/--	Strong	Aggressive
Entergy Mississippi Inc.	BBB/Negative/--	Strong	Aggressive

Entergy Gulf States Louisiana LLC	BBB/Negative/--	Strong	Aggressive
Entergy Texas Inc.	BBB/Negative/--	Strong	Aggressive
Entergy Corp.	BBB/Negative/--	Strong	Aggressive
System Energy Resources Inc.	BBB/Negative/--	Strong	Aggressive
Jersey Central Power & Light Co.	BBB/Negative/--	Excellent	Aggressive
Metropolitan Edison Co.	BBB/Negative/--	Excellent	Aggressive
Pennsylvania Electric Co.	BBB/Negative/--	Excellent	Aggressive
Cleveland Electric Illuminating Co.	BBB/Negative/--	Excellent	Aggressive
Ohio Edison Co.	BBB/Negative/A-2	Excellent	Aggressive
Pennsylvania Power Co.	BBB/Negative/--	Excellent	Aggressive
Toledo Edison Co.	BBB/Negative/--	Excellent	Aggressive
FirstEnergy Corp.	BBB/Negative/--	Strong	Aggressive
Northern Indiana Public Service Co.	BBB/Watch Neg/--	Excellent	Aggressive
Kansas City Power & Light Co.	BBB/Watch Neg/A-3	Strong	Intermediate
Great Plains Energy Inc.	BBB/Watch Neg/--	Strong	Intermediate
Tampa Electric Co.	BBB-/Stable/A-3	Excellent	Aggressive
Potomac Edison Co.	BBB-/Stable/--	Excellent	Aggressive
West Penn Power Co.	BBB-/Stable/--	Excellent	Aggressive
Monongahela Power Co.	BBB-/Stable/--	Excellent	Aggressive
Westar Energy Inc.	BBB-/Stable/--	Excellent	Aggressive
Kansas Gas & Electric Co.	BBB-/Stable/--	Excellent	Aggressive
Consumers Energy Co.	BBB-/Stable/--	Excellent	Aggressive
CMS Energy Corp.	BBB-/Stable/A-3	Excellent	Aggressive
Ohio Valley Electric Corp.	BBB-/Stable/--	Excellent	Aggressive
TECO Energy Inc.	BBB-/Stable/--	Strong	Aggressive
Empire District Electric Co.	BBB-/Stable/A-3	Strong	Aggressive
Edison International	BBB-/Stable/--	Strong	Aggressive
Black Hills Power Inc.	BBB-/Stable/--	Strong	Intermediate
Arizona Public Service Co.	BBB-/Stable/A-3	Strong	Aggressive
Pinnacle West Capital Corp.	BBB-/Stable/A-3	Strong	Aggressive
Avista Corp.	BBB-/Stable/A-3	Strong	Aggressive

Allegheny Energy Inc.	BBB-/Stable/A-3	Strong	Aggressive
Union Electric Co. d/b/a AmerenUE	BBB-/Stable/A-3	Strong	Aggressive
Ameren Corp.	BBB-/Stable/A-3	Satisfactory	Aggressive
Black Hills Corp.	BBB-/Stable/--	Satisfactory	Intermediate
-			
Oncor Electric Delivery Co. LLC	BBB-/Watch Dev/--	Excellent	Intermediate
-			
Duquesne Light Co.	BBB-/Negative/--	Excellent	Highly leveraged
Duquesne Light Holdings Inc.	BBB-/Negative/--	Excellent	Highly leveraged
Entergy New Orleans Inc.	BBB-/Negative/--	Satisfactory	Aggressive
-			
Puget Sound Energy Inc.	BBB-/Watch Neg/A-3	Excellent	Aggressive
Puget Energy Inc.	BBB-/Watch Neg/--	Excellent	Aggressive
-			
Central Vermont Public Service Corp.	BB+/Stable/--	Excellent	Highly leveraged
Indianapolis Power & Light Co.	BB+/Stable/--	Excellent	Highly leveraged
IPALCO Enterprises Inc.	BB+/Stable/--	Excellent	Highly leveraged
-			
Commonwealth Edison Co.	BB/Positive/B	Satisfactory	Aggressive
Central Illinois Public Service Co.	BB/Positive/--	Satisfactory	Aggressive
Illinois Power Co.	BB/Positive/--	Satisfactory	Aggressive
Central Illinois Light Co.	BB/Positive/--	Satisfactory	Aggressive
CILCORP Inc.	BB/Positive/--	Satisfactory	Aggressive
-			
Nevada Power Co.	BB/Stable/--	Excellent	Highly leveraged
Sierra Pacific Power Co.	BB/Stable/--	Excellent	Highly leveraged
Sierra Pacific Resources	BB/Stable/B-2	Excellent	Highly leveraged
Tucson Electric Power Co.	BB/Stable/B-2	Strong	Highly

			leveraged
Aquila Inc.	BB-/Watch Pos/--	Satisfactory	Highly leveraged
Texas-New Mexico Power Co.	BB-/Stable/--	Satisfactory	Highly leveraged
Public Service Co. of New Mexico	BB-/Stable/B-2	Satisfactory	Highly leveraged
PNM Resources Inc.	BB-/Stable/B-2	Satisfactory	Highly leveraged

ARIZONA CORPORATION COMMISSION
STAFF'S SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172 – INTERIM RATES
JULY 31, 2008

Staff Interim 2.26 Refer to paragraph 31, of Mr. Brandt's 6/6/08 affidavit. Please identify, quantify and explain in detail the impact of the Pinnacle West \$460 million investment in APS had on APS's FFO/Debt ratios in 2005, 2006, 2007 and 2008. Provide all related calculations and quantifications.

Response: Attached as APS13022 is the impact to APS's FFO/Debt ratio due to Pinnacle West's \$460 million investment in APS for 2005, 2006, 2007 and 2008.

Witness: Donald Brandt

APS FFO to Debt ($000)

Line	Year Ended December 31,	2005	2006	2007	2008 (1)
1	Funds from Operations	522,518	695,558	753,821	908,656
2	Total Debt (with imputed debt)	3,182,613	3,801,599	4,061,778	3,942,244
3	FFO to Debt	16.4%	18.3%	18.6%	23.0%
	Adjusted to Remove $460 million of Equity Infusions:				
4	Funds from Operations	522,518	695,558	753,821	908,656
5	Lower FFO for interest on $460m of additional debt ($460 m x 7% x 60% after-tax)		(19,000)	(19,000)	(19,000)
6	FFO if $460m of equity infusions had not been made		676,558	734,821	889,656
7	Total Debt (with imputed debt)	3,182,613	3,801,599	4,061,778	3,942,244
8	Remove $460m of equity infusions, replace with debt	250,000	460,000	460,000	460,000
9	Total Debt if $460m of equity infusions had not been made	3,432,613	4,261,599	4,521,778	4,402,244
10	FFO to Debt	15.2%	15.9%	16.3%	20.2%

(1) 2008 FFO does not reflect any interim base rate relief and includes approximately $80 million of accelerated tax depreciation of the 2008 Economic Stimulus Act, the majority of which will not recur in 2009 forward. The Company's attrition pro forma includes the tax benefits from the 2008 Economic Stimulus Act.

Value Line Investment Survey *for Windows*®
Version 3.0

Value Line Investment Survey *for Windows*® Version 3.0

About Value Line

Value Line was founded in New York in 1931 by Arnold Bernhard, then a young analyst, amidst the crisis of confidence wrought by the Great Depression. His goal was to help investors in their quest to achieve superior returns from stocks by providing access to the same information that professionals had at their fingertips. His vision grew into one of the most enduring and trusted institutions in the financial world. Backed by disciplined, objective analytic methodologies that have been proven over six decades, and by one of the world's largest independent research staffs, including over 100 professional securities analysts, statisticians and economists, Value Line has become an indispensable source for investors around the globe. Value Line's businesses are broad-based, including financial publications and electronic data services, a family of no-load mutual funds, and asset management for retirement and endowment accounts. Its research services include domestic stocks, Canadian stocks, mutual funds, convertibles, and options, which are available in both print and electronic form.

Value Line's headquarters are located at 220 East 42nd Street, New York, NY 10017. Telephone 212-907-1500. For technical support, call 800-654-0508.

The Value Line Investment Survey

The Value Line Investment Survey printed version was created in 1931 for one purpose and one purpose only to guide you in your quest to realize superior returns on your invested capital. Based on disciplined, objective, quantitative, analytical methodologies that have proven themselves over the last 60 years, plus a staff of more than 70 professional securities analysts, Value Line can serve as an invaluable tool in making your investment decisions.

Average Price for the Year - The sum of the 52 Wednesday closing prices for the year divided by 52.

B

Backlog - Orders for goods and services that have been received, but not yet delivered or rendered.

Bank SL Deposits Latest Qtr - Customer deposits in short-term, marketable, liquid, low-risk debt securities for the latest quarter.

Bank SL Loans Latest Qtr - The total for loans outstanding for the latest quarter.

Basis Point - In the context of discussions on interest rates, one basis point equals one-hundredth of one percentage point.

Benefits & Reserves (Insurance) - Funds received from policy holders in ex change for promises to make future payments to the insured or third party in the event of sickness disability, or hospital confinement.

Beta - A relative measure of the historical sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Index. A Beta of 1.50 indicates a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Index. The "Beta coefficient" is derived from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are adjusted for their long-term tendency to converge toward 1.00. Additionally, Value Line shows betas computed based on monthly total returns for the trailing three year, five-year and 10-year periods.

Bond - A long-term debt instrument, characterized typically by fixed, semiannual interest payments and a specified maturity date.

Book Value Per Share - Net worth (including intangible assets), less preferred stock at liquidating or redemption value, divided by common shares outstanding, or common shareholder equity divided by common shares outstanding.

Federal Home Loan Bank Advances (Savings & Loans) (Thrifts) - Borrowings from the Federal Home Loan Bank at year end.

Federal Purchases - Consist largely of wages paid to Federal employees and Federal purchases of goods and services from businesses. Reported by the Commerce Department when it releases the Gross National Product (GNP) report.

Federal Reserve Board - The governing body of the Federal Reserve System, which regulates certain banks and is charged with setting national monetary policy. Often referred to as "the Fed."

FHLB Advances (Thrift Industry) - Borrowing from the regional Federal Home Loan Bank.

52-Week High Price - The highest trading value of a stock over the prior year.

52-Week Low Price - The lowest trading value of a stock over the prior year.

Financial Strength Rating - A relative measure of financial strength of the companies reviewed by Value Line. The relative ratings range from A++ (strongest) down to C (weakest), in nine steps.

Financial Times-Stock Exchange 100 (FT-SE 100) - A stock price index made of 100 of the largest stocks traded in London. The index is published by The Financial Times, a London-based financial newspaper.

Finding Cost (Natural Gas [Diversified] and Petroleum Industries) - The amount of money spent per barrel to increase proved reserves through acquisitions, discovery, or enhanced recovery.

Fiscal Year-End Date - The date of a company's fiscal year end.

5-Year Book Value Growth - See *Growth Rates.*

5-Year Cash Flow Growth - See *Growth Rates.*

5-Year Dividends Growth - See *Growth Rates.*

Residential Fixed Investment - Expenditures for housing reported by the Commerce Department in its regular Gross National Product (GNP) reports.

Retail Sales - A monthly measure of all U.S. retail activity, published by the Commerce Department.

Retained Earnings - When relating to the income account, represents net profit for the year less all common and preferred dividends. With respect to the balance sheet or common equity, it is the sum of net profit in all years of the company's existence less all dividends (common and preferred) ever paid. In this case, also known as earnings retained or earned surplus.

Return on Revenue - EPS expressed as a percentage to sales per share.

Revenue Passenger Miles (Air Transport Industry) - A measure of airline traffic. Each revenue passenger mile represents one revenue-paying passenger flown one mile.

Revenues (Electric Utility, Natural Gas/Distribution], Telecommunications Industries) - The amounts billed for services rendered.

Revenues (Real Estate Industry) - The total of rental, construction, and interest income and property sales.

Revenues Per Share - Gross revenues for the year divided by the number of common shares outstanding at year end.

Risk Arbitrage - See *Arbitrage*.

S

Safety Rank - A measurement of potential risk associated with individual common stocks. The Safety Rank is computed by averaging two other Value Line indexes - the Price Stability Index and the Financial strength Rating. Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit their purchases to equities ranked 1 (Highest) and 2 (Above Average) for Safety.

Sales or Revenues - Total sales revenue less returns, allowances, and sales discounts; also known as net sales.

STANDARD
&POOR'S

Security Owner's

Stock Guide

AUGUST 2008

Issue.

Issue with issuer in default on

rld, and certain other obligations or high variability in expected uch obligations are securities qulties, commodities, or curren-ly and principal only mortgage

aken as an indication that an total return.

hat there is insufficient informa-is not rate a particular type of

detailed indications of preferred be modified by the addition of hin the major rating categories.

estments that are rated 'AAA'.

an overall credit quality of 'AA'.

an overall credit quality 'A'.

h an overall credit quality 'BBB'.

BBB' may be modified to show

endation to purchase or sell a lered. In arriving at the rating. andard & Poor's earnings and

nished to Standard & Poor's by om other sources. It considers l or withdrawn as a result of

ting securities. Such compen-ar by issuers of such securities ion thereof.

EARNINGS AND DIVIDEND RANKINGS FOR COMMON STOCKS

The investment process involves assessment of various factors—such as products and industry position, corporate resources and financial policy—with results that make some common stocks more highly esteemed than others. In this assessment, Standard & Poor's believes that earnings and dividend performance is the end result of the interplay of these factors and that, over the long run, the record of this performance has a considerable bearing on relative quality. The rankings, however, do not pretend to reflect all of the factors, tangible or intangible, that bear on stock quality.

Relative quality of bonds or other debt, that is, degrees of protection for principal and interest, called credit worthiness, cannot be applied to common stocks, and therefore rankings are not to be confused with bond quality ratings which are arrived at by a necessarily different approach.

Growth and stability of earnings and dividends are deemed key elements in establishing Standard & Poor's earnings and dividend rankings for common stocks, which are designed to capsulize the nature of this record in a single symbol. It should be noted, however, that the process also takes into consideration certain adjustments and modifications deemed desirable in establishing such rankings.

The point of departure in arriving at these rankings is a computerized scoring system based on per-share earnings and dividend records of the most recent ten years—a period deemed long enough to measure significant time segments of secular growth, to capture indications of basic change in trend as they develop, and to encompass the full peak-to-peak range of the business cycle. Basic scores are computed for earnings and dividends, then adjusted as indicated by a set of predetermined modifiers for growth, stability within long-term trend, and cyclicality. Adjusted scores for earnings and dividends are then combined to yield a final score.

Further, the ranking system makes allowance for the fact that, in general, corporate size imparts certain recognized advantages from an investment standpoint. Conversely, minimum size limits (in terms of corporate sales volume) are set for the various rankings, but the system provides for making exceptions where the score reflects an outstanding earnings-dividend record.

The final score for each stock is measured against a scoring matrix determined by analysis of the scores of a large and representative sample of stocks. The range of *scores in the array of this sample has been aligned with the following ladder of rankings:*

A+ Highest	**A– Above Average**	**B– Lower**
A High	**B+ Average**	**C Lowest**
	B Below Average	**D In Reorganization**

NR signifies no ranking because of insufficient data or because the stock is not amenable to the ranking process.

The positions as determined above may be modified in some instances by special considerations, such as natural disasters, massive strikes, and non-recurring accounting adjustments.

A ranking is not a forecast of future market price performance, but is basically an appraisal of past performance of earnings and dividends, and relative current standing. These rankings must not be used as market recommendations; a high-score stock may at times be so overpriced as to justify its sale, while a low-score stock may be attractively priced for purchase. Rankings based upon earnings and dividend records are no substitute for complete analysis. They cannot take into account potential effects on management changes, internal company policies not yet fully reflected in the earnings and dividend record, public relations standing, recent competitive shifts, and a host of other factors that may be relevant to investment status and decision.

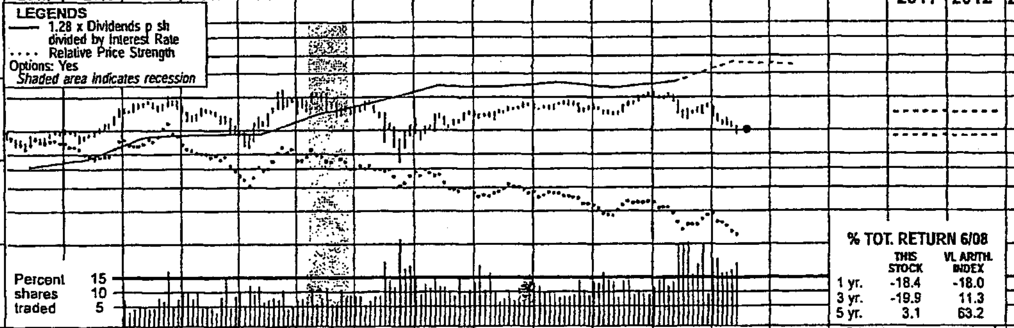
NOTE – Standard & Poor's Earnings and Dividend Rankings ("Rankings") may be used only for the subscriber's internal use, or as part of the subscriber's analysis of common stocks for investment purposes in the ordinary course of subscribers' businesses; provided, however, that in no event may the Rankings be redistributed to third parties. Use of the Rankings as part of the express investment strategy for any mutual fund, unit investment trust, variable annuity or other pooled investment vehicle is subject to the express written agreement of Standard & Poor's.

PINNACLE WEST NYSE-PNW

RECENT PRICE 32.11 | P/E RATIO 12.8 (Trailing: 11.6 Median: 14.0) | RELATIVE P/E RATIO 0.83 | DIV'D YLD 6.5% | VALUE LINE

TIMELINESS 4 Lowered 6/6/08
SAFETY 2 Lowered 8/8/08
TECHNICAL 4 Lowered 6/20/08
BETA .80 (1.00 = Market)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
High:	42.8	49.3	43.4	52.7	50.7	46.7	40.5	45.8	46.7	51.0	51.7	42.9
Low:	27.6	39.4	30.2	25.7	37.7	21.7	28.3	36.3	39.8	38.3	36.8	30.3



2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+25%)	11%
Low	30	(-5%)	5%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	2	0	0	0	0	0	0
to Sell	0	0	2	0	0	0	0	0	0

Institutional Decisions

	3Q2007	4Q2007	1Q2008
to Buy	135	151	133
to Sell	135	125	136
Hld's(000)	87323	82999	84951

% TOT. RETURN 6/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	-18.4	-18.0
3 yr.	-19.9	11.3
5 yr.	3.1	63.2

1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
19.39	19.66	19.28	19.08	20.77	23.52	25.12	28.57	43.50	53.66	28.90	30.87	31.59	30.16	34.03	35.07	37.25	39.65	Revenues per sh	46.80
4.70	5.25	5.09	5.16	5.90	7.12	7.34	7.73	7.99	8.72	7.01	7.33	6.93	5.76	6.76	6.69	6.85	7.35	"Cash Flow" per sh	9.05
1.73	1.95	1.99	2.22	2.47	2.76	2.85	3.18	3.35	3.68	2.53	2.52	2.58	2.24	3.17	2.96	2.80	2.90	Earnings per sh A	3.15
--	.20	.83	.93	1.03	1.13	1.23	1.33	1.43	1.53	1.63	1.73	1.83	1.93	2.03	2.10	2.10	2.12	Div'd Decl'd per sh B■†	2.30
2.57	2.69	2.92	3.38	2.95	3.63	3.76	4.05	7.76	12.27	9.81	7.60	5.86	6.39	7.38	9.14	10.55	11.80	Cap'l Spending per sh	9.35
17.00	18.87	20.32	21.49	22.51	23.90	25.50	26.00	28.09	29.46	29.44	31.00	32.14	34.57	34.47	35.15	35.85	36.60	Book Value per sh C	39.10
87.16	87.42	87.43	87.52	87.52	84.83	84.83	84.83	84.83	84.83	91.26	91.29	91.79	99.08	99.96	100.49	100.70	100.90	Common Shs Outst'g D	101.50
10.8	11.5	9.6	10.8	11.8	11.8	15.2	11.9	11.3	12.0	14.4	14.0	15.8	19.2	13.7	14.9	Bold figures are		Avg Ann'l P/E Ratio	10.5
.66	.68	.63	.72	.74	.68	.79	.68	.73	.61	.79	.80	.83	1.02	.74	.79	Value Line		Relative P/E Ratio	.70
--	.9%	4.3%	3.9%	3.5%	3.5%	2.8%	3.5%	3.8%	3.5%	4.5%	4.9%	4.5%	4.5%	4.7%	4.8%	estimates		Avg Ann'l Div'd Yield	7.0%
						2130.6	2423.4	3690.2	4551.4	2637.3	2817.9	2899.7	2988.0	3401.8	3523.6	3750	4000	Revenues ($mill)	4750
						252.6	270.8	283.6	312.2	215.2	230.6	235.2	223.2	317.1	298.8	280	290	Net Profit ($mill)	320
						39.5%	38.3%	44.1%	40.6%	39.1%	31.4%	35.4%	36.2%	33.0%	33.6%	34.0%	34.0%	Income Tax Rate	34.0%
						7.4%	4.3%	7.6%	15.3%	20.5%	6.2%	6.9%	10.4%	6.6%	14.8%	4.0%	4.0%	AFUDC % to Net Profit	4.0%
						47.6%	50.0%	45.1%	51.7%	51.8%	50.6%	46.7%	43.2%	48.4%	47.0%	48.5%	49.5%	Long-Term Debt Ratio	50.0%
						50.2%	50.0%	54.9%	48.3%	48.2%	49.4%	53.3%	56.8%	51.6%	53.0%	51.5%	50.5%	Common Equity Ratio	50.0%
						4307.6	4411.8	4337.8	5172.4	5567.9	5727.5	5535.2	6033.4	6678.8	6658.7	7010	7295	Total Capital ($mill)	7970
						4730.6	4778.5	5133.2	5907.3	6479.4	7480.1	7535.5	7577.1	7881.9	8436.4	9085	9825	Net Plant ($mill)	11345
						7.6%	7.9%	8.1%	7.6%	5.4%	5.5%	5.6%	5.0%	6.2%	5.9%	5.5%	5.5%	Return on Total Cap'l	5.5%
						11.2%	12.3%	11.9%	12.5%	8.0%	8.1%	8.0%	6.5%	9.2%	8.5%	8.0%	8.0%	Return on Shr. Equity	8.0%
						11.2%	12.2%	11.9%	12.5%	8.0%	8.1%	8.0%	6.5%	9.2%	8.5%	8.0%	8.0%	Return on Com Equity E	8.0%
						6.4%	7.1%	6.8%	7.3%	2.9%	2.6%	2.3%	1.0%	3.4%	2.5%	2.0%	2.0%	Retained to Com Eq	2.0%
						45%	42%	43%	41%	64%	68%	71%	85%	63%	70%	75%	73%	All Div'ds to Net Prof	73%

CAPITAL STRUCTURE as of 3/31/08
Total Debt $3486.3 mill. Due in 5 Yrs $1785.7 mill.
LT Debt $3114.6 mill. LT Interest $182.3 mill.
(LT interest earned: 3.0x)

Pension Assets-12/07 $1.32 bill. Oblig. $1.72 bill.

Pfd Stock None

Common Stock 100,633,751 shs.
MARKET CAP: $3.2 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2005	2006	2007
% Change Retail Sales (KWH)	+4.4	+5.6	+4.3
Avg. Indust. Use (MWH)	670	730	665
Avg. Indust. Revs. per KWH (¢)	6.28	6.87	7.30
Capacity at Peak (Mw)	7412	7652	6783
Peak Load, Summer (Mw)	7000	7652	7545
Annual Load Factor (%)	50.0	48.0	51.4
% Change Customers (yr-end)	+4.3	+4.4	+3.3
Fixed Charge Cov. (%)	278	324	291

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	4.5%	-4.5%	6.0%
"Cash Flow"	.5%	-4.0%	6.0%
Earnings	1.0%	-2.5%	2.0%
Dividends	7.0%	5.5%	2.0%
Book Value	4.5%	3.5%	2.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	585.0	755.8	955.6	691.6	2988.0
2006	670.2	925.0	1076.5	730.1	3401.8
2007	695.1	863.4	1205.9	759.2	3523.6
2008	736.7	926.2	1260	827.1	3750
2009	800	990	1320	890	4000

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.26	.88	.86	.24	2.24
2006	.12	1.11	1.84	.10	3.17
2007	.16	.78	1.99	.03	2.96
2008	d.04	1.33	1.40	.11	2.80
2009	.20	.85	1.70	.15	2.90

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.45	.45	.45	.475	1.83
2005	.475	.475	.475	.50	1.93
2006	.50	.50	.50	.525	2.03
2007	.525	.525	.525	.525	2.10
2008	.525	.525			

BUSINESS: Pinnacle West Capital Corporation (parent of Arizona Public Service) supplies electricity to approx. 1,780,000 people in 11 of 15 Arizona counties. Electric revenue sources: residential, 51%; commercial, industrial, and other, 49%. Power costs: 39% of electric revenues; labor costs: 13% of total revenues. The mining industry is the largest industrial customer. Energy sources: coal, 37%; nuclear, 22%; gas & other, 18%; purchased power, 23%. Has 7,600 employees. Reported '07 depreciation rate: 3.1%. Est'd plant age: 10 years. Chairman & Chief Executive Officer: William J. Post. Pres.: Jack E. Davis. Inc.: Arizona. Address: 400 E. Van Buren St., Suite 700, P.O. Box 52132, Phoenix, AZ 85072-2132. Tel.: 602-379-2568. Internet: www.pinnaclewest.com.

Pinnacle West has a rate request in the hopper. The filing for a $278 million increase is largely for nonfuel-related items. Some $53 million would recoup the cost of new customer connections. Other components include $131 million for rate base increases and $48 million to update the utility subsidiary's cost of capital. The petition also calls for a $79 million attrition adjustment to offset earnings erosion between the end of the test year and 2010. It seeks only $14 million in higher fuel costs, because $70 million will be collected through the power supply adjuster. PNW asked regulators to make the order effective October 1, 2009.

The company is taking action on several fronts to meet rising demand. For starters, it is stringing a 122-mile, 500-kilovolt line from the Palo Verde nuclear station's hub to Yuma, Arizona. On completion, the line will have the capacity to deliver 1,200 megawatts (mw) of power. Too, PNW and partners are exploring construction of a 600-mile, $3 billion line from Wyoming to access inexpensive coal and wind-driven power. On the generation side, PNW recently began operating a two-unit, 96-mw gas-fired plant and has contracted to buy 280 mw of output from a solar facility, which will be built, provided that the federal government grants the necessary tax credits. Finally, the demand-side-management program is effectively reducing power consumption.

Earnings are off to a sluggish start in 2008. March-interim results were hurt by a number of plant overhauls and weakness in SunCor's land sales. The rest of the year should benefit from increased wholesale revenues, favorable rulings on some tax matters, and an expected mid-year transmission revenue increase. Overall, we estimate 2008 earnings will decline 5%, to $2.80 a share. Customer growth and higher rates point to improvement next year. For now, the stock is untimely.

Near-term prospects depend heavily on the outcome of the pending rate case. We expect no hike in the payout until an order is issued. A reasonable increase, which we consider likely, suggests resumption of dividend growth. For the long term, PNW remains an above-average utility choice.

Arthur H. Medalie *August 8, 2008*

(A) Diluted egs. Excl. nonrecurring gains (losses): '93, 22¢; '94, 31¢; '95, net 6¢; '99, ($1.20); '02, (77¢); excl. gains (losses) from discontinued ops.: '92, 7¢; '99, ($1.97); '00, 22¢; '05, (36¢); '06, 10¢. Next earnings report due late Oct. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Divd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. def. chgs. In '07: $7.36/sh. (D) In mill. (E) Rate base: Fair value. Rate all'd on com. eq. in '05: 10.25%; earned on avg. com. eq., '07: 8.6%. Reg. Clim.: Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	20
Earnings Predictability	60

¶ S&P 500 # MidCap 400 ♦ SmallCap 600 • Options

Index	Ticker	Name of Issue (Call Price of Pfd. Stocks)	Market	Com. Rank. & Pfd. Rating	Inst. Hold Cos	Inst. Hold Shs. (000)	Principal Business	Price Range 1986-06 High	1986-06 Low	2007 High	2007 Low	2008 High	2008 Low	July, 2008 Jul. Sales in 100s	Last Sale Or Bid High	Low	Last	%Div Yield	P-E Ratio	EPS 5 Yr Growth	% Annualized Total Return 12 Mo	36 Mo	Cash Divs. Ea. Yr. Since
♦1	PNY	Piedmont Natural Gas	NY,Ph,Ch,P,B	A	424	37137	Gas Utilities	28.44	4.25	27.98	22.00	27.95	24.01	66275	27.06	25.00	26.78	3.9	17	6	9.5	6.2	1956
2•[1]	PIR	Pier 1 Imports	NY,Ph,Ch,P,B	C	298	89905	Homefurnishing Retail	26.44	1.25	9.06	3.26	8.25	3.03	427336	4.08	3.03	3.70	...	d	Neg	−49.3	−34.6	...
3	PEC	Pike Electric	NY,P	NR	206	19219	Construction & Engineering	21.80	13.60	24.39	13.99	18.27	12.75	31167	18.27	15.90	17.80	...	31	4	−15.5	0.0	...
4•[2]	PPC	Pilgrim's Pride	NY,Ph,Ch,P,B	B	332	44588	Packaged Foods & Meats	40.23	2.41	41.00	22.52	28.83	11.25	632397	16.52	11.25	12.19	0.7	d	Neg	−65.2	−27.8	1987
5	PNCL	Pinnacle Airlines	NDS	NR	232	20344	Airlines	18.00	4.41	20.34	13.58	16.09	2.95	67239	6.45	2.95	5.94	...	4	1	−66.5	−16.9	...
6	PCLB	Pinnacle Bancshares	AS,Ch,P,BB	B+	15	160	Regional Banks	18.75	2.00	15.88	10.00	12.45	7.50	358	9.25	7.50	9.00	4.9	NA	1	−35.4	−12.0	1987
7	PNS	Pinnacle Data Systems	AS,P	B−	14	1212	IT Consulting & Other Svcs	7.37	0.26	3.05	1.30	2.65	1.17	676	1.45	1.17	1.45	...	8	5	−36.5	−24.8	...
♦8•[1]	PNK	Pinnacle Entertainment	NY,Ch	NR	427	74301	Casinos & Gaming	37.40	3.92	36.17	22.78	23.74	7.76	390136	12.53	7.76	11.30	...	NM	93	−63.1	−20.3	...
9	PNFP	Pinnacle Finl Partners	NDS	NR	194	6758	Regional Banks	37.41	2.00	33.85	21.62	29.29	19.30	32909	26.00	19.30	25.21	...	20	32	0.2	1.5	...
¶10•[3]	PNW	Pinnacle West Capital	NY,Ph,Ch,P,B	B+	726	86353	Electric Utilities	52.68	5.00	51.67	36.79	42.92	30.28	227229	33.83	30.34	33.57	6.3	13	4	−15.7	−7.2	1993
♦11	PDC	Pioneer Drilling	AS,Ch	NR	375	47460	Oil & Gas Drilling	23.06	0.37	16.24	11.36	20.75	8.95	140862	19.25	15.32	15.89	...	NIL	...	23.7	3.5	...
#12•[4]	PXD	Pioneer Natural Resources	NY,Ph,Ch,B	B	566	107673	Oil & Gas Exploration & Prod	56.35	5.00	54.87	35.51	82.21	36.37	495649	82.21	57.18	59.45	0.5	9	6	30.3	13.0	2004
13	PSE	Pioneer So.West Ener Ptnrs LP	NY,Ch,P	NR	1	318	Oil & Gas Exploration & Prod	...	...	...	...	22.68	18.92	16525	22.68	19.08	20.08	10.0	9	1	0.0	0.0	2008
♦14•[5]	PJC	Piper Jaffray Companies	NY,Ch	NR	396	15638	Investment Bank & Brokerage	74.65	26.10	74.30	41.44	49.40	24.68	124959	38.26	24.68	35.50	...	49	6	−28.7	2.2	...
15	PP	Pipex Pharmaceuticals	AS,Ch	NR	18	2544	Pharmaceuticals	19.50	1.66	30.00	3.06	8.25	0.63	7266	1.02	0.63	0.75e	...	4	3	−90.1	0.0	...
¶16•[6]	PBI	Pitney Bowes	NY,Ph,Ch,P,B	B+	948	176491	Office Services & Supplies	73.31	5.68	49.70	36.40	39.39	31.20	313568	34.03	31.20	31.69	4.4	11	−10	−28.7	−7.1	1934
17	PBI.P	Pitney Bowes $2.12 Cv Pref	NY,Ch	NR	2	1.5		850.00	505.00	796.27	580.00	600.00	557.00	...	800.00	400.00	600.00e	0.4	...	...	...	...	1979
18	PW	Pitts & W Va RR SBI	AS,Ch	B+	9	54	Specialized REITs	9.95	5.12	9.65	8.74	10.37	9.00	350	10.35	9.10	9.12	5.3	18	−10	13.3	8.4	1964
19	PZZI	Pizza Inn	NDS	C	11	5003	Food Distributors	6.62	0.68	3.37	1.84	3.09	2.19	1377	2.56	2.27	2.56	...	9	−32	−18.7	−2.8	...
20•[7]	PAA	Plains All Amer Pipeline LP	NY	NR	220	46332	Oil & Gas Storage & Transp	53.23	9.62	65.24	46.25	52.44	41.00	84568	47.95	41.00	46.07	7.7	16	...	...	...	1999
#21•[8]	PXP	Plains Explor & Prod'n	NY,Ch,P	NR	551	103010	Oil & Gas Exploration & Prod	49.73	8.08	57.08	35.31	79.86	40.72	566055	76.52	53.63	55.97	...	6	NM	24.5	13.7	...
22•[9]	PLNR	Planar Systems	NDS	C	143	11194	Elect Equip Manufacturers	32.87	5.00	10.81	5.47	8.67	2.08	22269	3.20	2.08	2.16	...	d	Neg	−69.0	−33.1	...
#23•[10]	PLT	Plantronics Inc	NY,Ph,Ch,B	B	491	48161	Communications Equipment	56.00	2.41	33.21	19.22	25.98	16.02	122292	25.06	20.45	24.35	0.8	18	4	−15.4	−11.4	2004
24	PLG	Platinum Group Metals	AS,BB,To	NR	24	19691	Precious Metals & Minerals	2.09	0.60	5.00	1.72	4.43	2.16	5895	3.45	2.70	2.85	...	d	1	−21.4	67.1	...
25•[11]	PTP	Platinum Underwriters Hldg	NY,Ph,Ch,P,B	NR	532	51168	Reinsurance	35.21	21.29	38.07	29.81	37.00	31.02	149740	36.44	31.02	36.10	0.9	6	27	2.8	3.7	2003
26	PTP.PA	Platinum Underwrts Hldgs 6% Cv	NY	BB+	27	2342		32.11	27.02	34.54	29.50	33.16	28.75	7836	31.50	28.75	31.23e	5.8	...	...	...	...	2006
27•[12]	PLA	Playboy Enterprises Cl'B'[53]	NY	B−	178	23626	Movies & Entertainment	36.12	3.37	12.00	8.87	9.16	4.46	38228	5.44	4.46	4.67	...	NM	83	−52.5	−26.9	...
28	PLA.A	Playboy Enterprises'A'	NY	...	16	1195		32.00	3.12	12.30	8.33	10.35	4.65	196	5.98	4.60	5.19	...	35	83	−53.4	−24.3	...
29	PLC	PLC Systems	AS	C	14	1272	Health Care Equipment	34.87	0.31	1.12	0.25	0.49	0.22	2908	0.43	0.22	0.25	...	d	−33	−61.0	−18.1	...
♦30•[13]	PLXS	Plexus Corp	NDS	B−	512	44515	Electronic Manufactur Svcs	81.00	0.50	32.47	15.78	32.17	17.78	148178	32.17	27.09	28.50	...	15	NM	25.8	28.9	...
31•[14]	PLUG	Plug Power	NDS	NR	130	39639	Electrical Component & Equip	156.50	3.39	4.75	2.42	4.19	1.82	120801	2.52	1.82	2.40	...	d	1	−23.7	−28.0	...
¶32•[15]	PCL	Plum Creek Timber	NY,Ph,Ch,P,B	B	931	112435	Specialized REITs	40.00	6.33	48.45	37.13	49.60	37.65	563818	49.60	41.00	48.72	3.4	41	4	18.1	12.7	1989
33	PCC	PMC Commercial Tr	AS,Ch	B	42	1315	Mortgage REITs	20.75	8.68	15.90	10.24	11.39	6.79	3162	8.60	7.40	7.90	11.4	6	1	−35.7	−7.4	1994
34•[16]	PMCS	PMC-Sierra Inc	NDS	C	485	228904	Semiconductors	255.50	0.81	9.83	6.06	9.15	4.21	1764270	8.20	6.69	7.24	...	20	4	−10.0	−8.8	...
#35	PMI	PMI Group	NY,Ph,Ch,P,B	A−	405	79601	Thrifts & Mortgage Finance	46.00	11.00	51.46	9.82	13.46	1.20	796991	3.74	1.20	2.51	2.0	...	Neg	−93.1	−59.0	1995
36	PNH	PNC Cap Tr E 7.75% TruPS	NY	...	13	34		...	...	...	...	25.39	16.83	12126	24.50	16.83	24.28	8.0	...	...	0.0	0.0	2008
¶37•[17]	PNC	PNC Financial Services Group	NY,Ph,Ch,P,B	B+	1300	230914	Regional Banks	75.81	7.87	76.41	63.54	73.00	49.01	1385264	72.95	49.01	71.29	3.7	15	1	3.3	10.9	1865
38	PNC.PC	PNC Finl Svcs $1.60 Cv C Pfd	NY	A−	3	2		123.00	61.25	125.00	107.01	120.00	88.00	19	125.00	87.00	118.00	1.4	...	...	...	...	1984
39	PNC.PD	PNC Finl Svcs $1.80 Cv D Pfd	NY	NR	3	3		123.00	59.14	125.50	105.13	118.10	85.00	33	126.00	85.00	114.00e	1.6	...	...	...	...	1985
#40	PNM	PNM Resources	NY,Ph,Ch,P,B	B	453	66942	Multi-Utilities	32.07	5.08	34.28	21.05	21.89	8.95	257401	12.95	10.72	11.71	7.9	d	−16	−56.3	−24.8	1996

Uniform Footnote Explanations-See Page 1. Other: [1]CBOE:Cycle 3. [2]CBOE,Ph:Cycle 3. [3]P:Cycle 1. [4]ASE:Cycle 3. [5]ASE,CBOE,P,Ph:Cycle 3. [6]ASE,P:Cycle 1. [7]ASE,CBOE,Ph:Cycle 2. [8]ASE,CBOE:Cycle 2. [9]ASE,Ph:Cycle 3. [10]ASE:Cycle 2. [11]CBOE,P:Cycle 1. [12]Ph:Cycle 3. [13]ASE,CBOE:Cycle 3. [14]ASE,CBOE,P:Cycle 3. [15]ASE,Ph:Cycle 2. [16]ASE,CBOE,P,Ph:Cycle 2. [17]CBOE,P,Ph:Cycle 2.
[51]Fiscal Mar'07 & prior [52]As defined [53]non-vtg [54]4 com per 2.4 pfd

Common and Convertible Preferred Stock

Index	Splits Dividends ♦ Latest Payment Period $	Date	Ex. Div.	Total $ So Far 2008	Ind. Rate	Paid 2007	Financial Mil-$ Cash & Equiv.
1♦	Q0.26	7-15-08	6-23	0.77	1.04	0.99	9.57
2	Div Omitted 10-3-06			...	0.40	...	80.2
3	None Paid			...	NIL	...	4.47
4	Q0.023	6-27-08	6-11	0.045	0.09	0.09	107
5	None Paid			...	NIL	...	81.9
6	Q0.11	6-20-08	6-5	0.22	0.44	0.44	Total D
7	None Paid			...	NIL	...	0.28
8	None Paid			...	NIL	...	203
9♦	None Paid			...	NIL	...	Total D
10	Q0.52½	9-2-08	7-30	1.575	2.10	2.10	17.5
11	None Paid			...	NIL	...	76.7
12	S0.14	4-14-08	3-27	0.14	0.28	0.27	17.3
13	Plan qtly div			...	1.24	...	
14	None Paid			...	NIL	...	Total As
15♦	None Paid			...	NIL	...	8.76
16	Q0.35	9-12-08	8-13	1.05	1.40	1.32	465
17	Q0.53	10-1-08	9-11	2.12	2.12	2.12	Conv Int
18	Q0.12	6-30-08	6-5	0.25	0.48	0.52	Total As
19	Div Postponed 12-29-00			...	NIL	...	1.01
20	Q0.88¾	8-14-08	7-31	2.60¼	3.55	3.28¼	NA
21	None Paid			...	NIL	...	67.9
22	None Paid			...	NIL	...	9.76
23	Q0.05	9-10-08	8-6	0.15	0.20	0.20	163
24	None Paid			...	NIL	...	7.33
25	Q0.08	9-30-08	8-28	0.24	0.32	0.32	Total Ass
26	Q0.45¾	8-15-08	7-30	1.358	1.81	1.81	Cv into 0.
27	None Paid			...	NIL	...	22.1
28	None Paid			...	NIL	...	
29	None Paid			...	NIL	...	6.84
30	None Paid			...	NIL	...	146
31	None Paid			...	NIL	...	146
32	Q0.42	5-30-08	5-14	0.84	1.68	1.68	118
33	Q0.22½	7-9-08	6-26	0.725	0.90	1.30	Total Ass
34	None Paid			...	NIL	...	285
35	Q0.01¼	7-15-08	6-26	0.07½	0.05	0.21	Total Ass
36	Plan qtly div			0.657	1.938	...	
37	Q0.66	7-24-08	7-9	1.95	2.64	2.44	Total Depo
38	Q0.40	10-1-08	9-3	1.60	1.60	1.60	Cv into 1.6
39	Q0.45	10-1-08	9-3	1.80	1.80	1.80	Cv into 1.6
40♦	Q0.23	5-2-08	4-7	0.46	0.92	0.91	27.7

♦Stock Splits & Divs By Line Reference Index [1]2-for-1,'04 [9]2-for-1,'04

ARIZONA CORPORATION COMMISSION
STAFF'S SEVENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDU
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
AUGUST 19, 2008

Staff Interim 7.3 Please provide copy of all reports on Pinnacle West by security analysts for the period 2007 to the present.

Response: This information was previously provided in response to Staff 2.7. Subsequent to that response, Bank of America released an additional report, which is attached hereto at APS08487.

Witness: Donald Brandt

Bank of America

August 4, 2008 **Electric Utilities**

Quarterly Review - Week 1

Fuel and Non-Fuel Costs on the Rise; Sector Rotation in Effect?

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Top Picks

Ticker	Rating	Price	Target
AEP	B	$39.39	$52.00
CMS	B	$13.41	$19.00

Least Favorites

Ticker	Rating	Price	Target
AEE	N	$40.07	$45.00
PNW	N	$31.85	$34.00

- **Mixed Earnings During Last Week's Quarterly Results.** The last two weeks saw fifteen companies under coverage report 2Q08. Nine reported equal or above consensus, while six came in below. The average earnings came in $0.05 per share above consensus; excluding Constellation (which reported $0.80 above consensus), the average earnings would have been $0.01 a share below the Street. The biggest misses came from a combination of regulated and deregulated utilities, with the largest coming from DTE at -$0.27 versus consensus.

- **Wholesale Prices Help But Costs Are On The Rise.** Picking up from 1Q08 trends, wholesale prices continue to climb over 2Q07, as higher natural gas prices drove power prices higher. By the same token, higher coal prices are starting to hurt some companies this quarter. Furthermore, forward heat rates continued to decline, a trend that started during 1Q08. Operating and maintenance (O&M) expenses are also rising faster than originally expected; Xcel's disappointing earnings were primarily driven by higher O&M.

- **Broader Market Dynamics Affecting Utility Performance.** While we would not characterize the quarter so far as being anywhere close to good, the stocks have responded much more negatively, with the Philadelphia Utility (UTY, 492.95) dipping below 500, which seemed to be a support level. A number of issues are affecting utility stocks: 1) concerns over higher realized coal prices finally affecting gross margins, 2) continued worry over contracting heat rate, 3) rising non-fuel costs, and 4) the ever-elusive sector rotation.

- **PPL Brings Down Guidance; Story Was Always About 2010.** Of all the stocks hit on Friday, none took it as hard as PPL, which was down 6.2% for the day. While the stock should have underperformed the UTY given management's negative comments on 2008 and 2009, we believe the drop was an over-reaction. Ultimately, PPL's earnings in 2010 continue to be the value driver for the stock. Our 2010 estimate of $4.50 per share and our $57 price target remain unchanged.

- **Earnings and Price Target Changes on Pages 2 and 3.** We are adjusting our 2008 earnings estimates for the companies listed on page 2. We are adjusting our price targets down for Ameren (down $2 to $45), Entergy (down $4 to $122), and Pinnacle West (down $1 to $34). Our lowered target for Entergy reflects reduced utility growth, delays in the Enexus spin, and higher interest costs at Enexus.

- **Exelon Added to Fresh Money List.** Given the recent weak performance of some of the generators, we are adding Exelon to our Value Plays, replacing Duke Energy. Over the last month, Exelon is down 16.5% versus the UTY down 9.1%.

- **Expectations for Upcoming Week.** This week, 10 of the 27 electric utilities under coverage report. We expect the remaining companies to come more or less in line, as we have not identified any particular outliers.

- **Sector View:** We believe utilities with commodity exposure offer value. Growing rate base favors utility fundamentals. While increasing Treasury yield could threaten defensive utilities, these should offer decent protection in a tough tape. Merchant units tied to natural gas outlook.

- **PORTFOLIO MANAGERS' SUMMARY: Page 2.**

respectively. Management did not update segment guidance, but now expects FP&L's earnings to fall short of original expectations and FPL Energy to outperform. Previously given segment guidance for FP&L was $2.15 to $2.20 per share and guidance for FPL Energy was $1.88 to $1.98 per share. We are at $2.15 per share for FP&L and $2.11 per share at FPL Energy. We are maintaining our Buy rating and price target of $74.

Pinnacle West Capital Corp. (PNW, $32.94, Neutral, Target Price: $34.00)

We are maintaining our Neutral rating but revising our price target down to $34 from $35. We are revising our FY08-FY10 earnings estimates upward to $2.46 per share, $2.46 per share and $2.85 per share. Our previous estimates were $2.33 per share, $2.27 per share and $2.66 per share, respectively. Our revision is based on the changes in our rate case assumption and financing activities.

Pinnacle West has an interim rate case pending before the Arizona Corporation Commission (ACC) and is seeking an interim increase of $115 million. With three commissioners changing seats this November, we believe that it is likely to see the resolution of this case before the election. However, we assume that Arizona Public Service will receive about 75% of its request. We expect this interim increase to be in effect through 2009 as we believe that the general rate case will not be resolved before October 2009. Previously, we assumed no changes in rate in 2009. With three new commissioners reviewing the rate case, we believe that there may be some delay in reaching a final decision. We continue to expect to see the full year benefit of the higher rates in 2010. We assume that Arizona Public Service to receive about 60% of its $225 million rate increase request.

Pinnacle West announced that it plans to reduce its capital expenditure by at least $500 million starting late 2008. With the reduction in the capital spending, Pinnacle West stated that the possibility of equity issuance can be deferred. In other words, Pinnacle West believes that equity issuance will not take place in 2008. We expect Pinnacle West and Arizona Public Service to utilize its short-term borrowing to fill its financial needs in 2008. We believe that equity issuance will not be necessary until FY10. We assume $200 million of equity issuance in FY10 in our model.

Pinnacle West revised its 2008 ongoing earnings guidance to $2.50 per share. Previous guidance was GAAP earnings of $2.50 per share. As the previous included some of the non-recurring items such as one-time tax benefit, we had estimated the ongoing guidance to be $2.28 per share after we adjusted for known one-time items. Thus, Pinnacle West essentially increased its ongoing guidance by about $0.22 per share, in our view. We believe that this reflects the $19 million gain from the sale of large real estate asset in 2Q08 as well as the benefits from higher retail and transmission rates.

2Q08 reported earnings for Pinnacle West was $1.33 per share, which included one-time tax benefit of $0.30 per share. After we adjust for this item, we believe that the operating earnings were $1.03 per share. Higher retail and transmission rates as well as a large real estate transaction were positive drivers in 2Q08 results.

Figure 6: Pinnacle West Sum-of-the-Parts Valuation

2009E Utility EPS	$ 2.43
Multiple	13.0x
	$ 31.53
Value of SunCor	$ 2.83
Price Target	$ 34.00

Source: Banc of America Securities LLC estimates.

PPL Corp. (PPL, $44.05, Buy, Target Price: $57.00)

PPL lowered 2008 guidance to $2.25 to $2.35 per share from $2.35 to $2.45 per share. While formal 2009 guidance will not be released until the third quarter earnings call, management indicated that FY09 earnings will be lower than FY08 earnings. PPL's original plan for 2009 was to achieve the midpoint of 2008 guidance at $2.40 per share, leaving it flat year over year. Management highlighted rising coal and transportation prices and lower results from marketing and trading activities for the reduction in FY08 guidance. For 2008, management now projects an additional $40 million in fuel expense over the original plan. FY09 earnings are expected to suffer from rising coal prices and the reduced expectations for SO_2 allowance gains, which were to offset the higher operating costs of the scrubbers. The total effect is expected to be approximately $210 million pre-tax with $100 million related to coal and $110 million pre-tax related to SO_2.

We are adjusting our FY08, FY09, and FY10 estimates down to $2.30/sh, $2.14/sh, and $4.47/sh from $2.45/sh, $2.67/sh, and $4.50/sh, respectively. While the new FY08 and FY09 estimates reflect the above cost pressures, the new FY10 earnings reflect a delayed share buy back program. We had previously assumed about $700 million in share buybacks in 2009, we now expect the share buy backs to occur in 2010. Our price target remains unchanged at $57.

PPL reported second quarter earnings of $0.50 per share, compared to $0.63 a year ago. After adjusting for one time items in 2007, a $0.08 tax benefit related to the U.K. businesses, $0.03 of divested Latin America assets, and $0.02 of synfuels, earnings were flat year over year. Other negative drivers at the supply segment were higher fuel prices, lower base load generation, and higher operating expenses. Partially offsetting these were improved margins from energy marketing and trading activities. Additional positive drivers at the international segment were higher rates due to the annual adjustment for inflation, high sales volumes, and lower pension expenses.

EXHIBIT
S-4

ALL-STATE LEGAL®

ARIZONA CORPORATION COMMISSION
STAFF'S SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCH
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RE
E-01345A-08-0172 – INTERIM RATES
JULY 31, 2008

Staff Interim 2.6 Please provide all rating agency reports in 2007 and 2008 addressing (a) APS, (b) Pinnacle West, (c) other electric utilities, and (d) the electric utility industry.

Response: (a)-(d). All responsive articles as listed below within APS's possession are attached hereto as APS13041 through APS13073.

Fitch 2008-01-23 – APS13041
Fitch_2007-06-21 - APS13042
Fitch_2007-12-21 - APS13043
Fitch_2008-01-23 - APS13044
Moodys_ 2007-05-07 -APS13045
Moodys_ 2007-06-21 - APS13046
Moodys_2007-02-23 - APS13047
Moodys_2007-12-17 - APS13048
Moodys_2007-12-17_II - APS13049
Moodys_2008-07-25 - APS13050
Moodys_2008-07-28 - APS13051
Moodys_2008-07-28_II - APS13052
SP 2007-01-16 I – APS13053
SP 2007-01-16 II – APS13054
SP 2007-01-16 III - APS13055
SP 2007-01-16 - APS13056
SP 2007-02-22 - APS13057
SP 2007-04-30 - APS13058
SP 2007-06-28 - APS13059
SP 2007-07-02 I - APS13060
SP 2007-07-02 - APS13061
SP 2007-07-11 I - APS13062
SP 2007-07-11 - APS13063
SP 2007-10-01 - APS13064
SP 2008-01-31 I - APS13065
SP 2008-01-31 - APS13066
SP 2008-02-04 - APS13067
SP 2008-02-14 - APS13068
SP 2008-04-14 - APS13069
SP 2008-06-25 I - APS13070
SP 2008-06-25 II - APS13071
SP 2008-06-25 III - APS13072
SP 2008-06-25 - APS13073

Witness: Donald Brandt

STANDARD & POOR'S

RatingsDirect®

June 25, 2008

Summary:
Pinnacle West Capital Corp.

Primary Credit Analyst:
Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

Table Of Contents

Summary:

Pinnacle West Capital Corp.

Credit Rating: BBB-/Stable/A-3

Rationale

Standard & Poor's Ratings Services today affirmed the 'BBB-' corporate credit rating assigned to Pinnacle West Capital Corporation (PWCC) and its utility, Arizona Public Service. The outlook is stable. The consolidated credit ratings of PWCC primarily reflect the operations of its largest subsidiary, APS, a regulated, electric utility serving about 1.1 million customers within its service territory, which spans roughly two-thirds of Arizona and includes about half of the Phoenix MSA. We view the business profile of PWCC and APS to be 'strong'. While the company continues to benefit from a number of favorable attributes including a good service territory, a reasonably balanced power supply portfolio and a good PSA. However, APS' continues to face significant regulatory challenges.

APS provided the company with about 92% of its consolidated net income in 2007. SunCor, PWCC's real estate development company, provided about 4%, but due to the significant real estate slowdown in the southwest, it is unlikely it will be a meaningful contributor of cash flows or income over the next several years. (Prior to the real estate downturn, our forecasts have conservatively limited earnings from this subsidiary due to the cyclic nature of its cash flows.) Other subsidiary operations include Pinnacle West Trading and Marketing, which contributed about 4% of consolidated net income in 2007. This subsidiary has since last year been minimizing trading operations. Its largest contract was serving all-requirements load for UNS Electric Inc., which ended in May 2008.

We view the financial profile of PWCC and APS to be 'aggressive', which reflects: year-end debt to total capitalization of 57% (adjusted for items such as power purchases and operating leases); heavy capital spending that is expected to drive negative free operating cash flow for the foreseeable future; cash flow weakness as a function of protracted rate cases; and, while modest, the presence of unregulated activities, which can be unpredictable in their earnings contributions.

Because the preponderance of cash flows for consolidated operations stems from APS, we expect financial performance will continue to be heavily dependent on regulatory outcomes. The conclusion of APS' last general rate case in June 2007 (filed in November 2005 and revised in early 2006) provided the company with mechanisms to recover legacy deferrals and speed the recovery of fuel costs going forward. This rate relief, in place for the last half of 2007, assisted the company in maintaining credit metrics roughly in line with past performance. Funds from operations (FFO) to total debt was about 16% at year-end, with FFO interest coverage around 4x. On a trailing 12-month basis the company's performance has been slightly above these levels, due in part to the federal tax stimulus package approved by the U.S. Congress earlier this year, which is expected to increase deferred taxes (which are added back to FFO and thus increase this total).

We expect APS to be in more or less continuous rate case mode for the next few years. Given APS' capital spending program, forecasted to be about $1.1 billion annually through 2010, the utility will need to file regular general rate cases to manage recovery of its investment. The use of a historical test year in Arizona, coupled with the fact that fully litigated rate cases take between 18 to 24 months to complete, is expected to result in no meaningful improvement in financial performance through 2009 and possibly beyond, depending on the timing and the

outcome of the company's current case.

APS filed its current rate case in March 2008. ACC staff requested that the company revise its filing to reflect a test year ending Dec. 31, 2007 (as opposed to the originally filed version based on a Sept. 30, 2007, test year). The revised case has not been officially certified by the ACC, but certification is expected by July 2. Unlike the company's last rate case, in which $315 million of the $322 million of rate relief granted was for fuel and power-related costs, the majority of the current case is for nonfuel expenditures.

While the revised case increased the company's request to $278 million (about an 8.5% increase, excluding the company's request that customers be assessed about $53 million in impact fees), the re-filing means that is unlikely the ACC will reach an outcome in the case before October 2009, and because the majority of APS' sales occur in the summer months, the company's financial performance could weaken in 2009.

This month, the company requested that the ACC allow it to continue to collect a $0.004/kWh charge that it has been collecting in 2007 to recover legacy purchased power and fuel deferrals. Given that the portion of deferred costs associated with this surcharge is due to be paid by July or August, APS has asked that the ACC continue the charge, but authorize collection as an interim base rate increase, subject to refund as part of the resolution of its rate case, expected in fall 2009. (Last year, the ACC approved similar relief for Tucson Electric Power in its pending rate case settlement when it granted the southern Arizona utility the opportunity to continue to collect charges related to a competitive transition charge, or CTC, while its rate case is pending.) While retail customers would essentially see no rate increase because APS is asking to continue the surcharge as an interim increase, it is unclear what action the ACC will take. A vote could occur as early as late summer.

In 2008, we expect a procedural schedule to be established for the APS rate case, and greater clarity around the timing of an outcome will be available once this is issued. Of note is that three of the five commissioners are facing term limits and will no longer be on the ACC beginning in 2009. Commissioners are popularly elected and about a dozen candidates have announced they will run for the November election. As a result, a majority of the commissioners presiding now will not be on the commission when an APS rate case ruling is rendered. What this means for credit quality is unclear.

APS was successful earlier this year in receiving approval for a change in its line extension policies, which eliminates the free footage allowance that used to be available for customers. As a result, the portion of the company's capital expenditures associated with new line extensions will be offset with contributions in aid of construction (CIAC). This is favorable and year to date ended March 31, 2008, had added about $10 million in incremental cash flows to the company. Because it is booked under investing activities, cash flow metrics are not improved, but we recognize the significant benefit of APS receiving upfront cash from customers to meet a portion of its distribution capital investment plans. Future cash flows from customers in the form of CIAC will depend on the number of new meter sets, which are significantly off year to date due to the poor real estate market in Arizona and a slowing economy generally.

APS has a well-diversified power supply portfolio that in 2007 consisted of about 22% nuclear generation, 37% coal generation, approximately 18% owned gas generation, and the balance, about 23%, of purchases. We would expect the company's purchased power obligations to steadily climb due to the fact that APS is under a self build moratorium until 2015. APS will also need to meet relatively stringent renewable portfolio standards (RPS). It has in place a surcharge to pass through to customers the costs of RPS compliance.

Palo Verde performance has stabilized, and it has a plan in place to address NRC concerns. As of the first quarter of 2008, the combined capacity factors for all three Palo Verde units was 93%, as compared with 79% for 2007 (which reflects in part an extended planned outage to replace steam generators at unit 3) and 71% in 2006, which largely reflects unplanned outages at unit 1 related to excessive vibration that occurred when that unit exited its extended outage for refueling and replacement of steam generators. Palo Verde Unit 3 remains in the NRC's "multiple/repetitive degraded cornerstone" column of the NRC's Action matrix, which subjects all three Palo Verde units to enhanced NRC inspection regime. Preliminary work in support of this took place throughout the summer of 2007. In February, the NRC issued its inspection report, which determined the plant was operating safely but which also outlined an improvement plan for APS. In late March, APS in turn submitted to the NRC a final improvement plant addressing issues raised in the NRC inspection report. While the nuclear units appear to be on a path to improve operational performance and restore NRC confidence in the operational and safety standards at the plant, this will remain an area of concern until the NRC removes it degraded designation.

Short-term credit factors

APS and PWCC's short-term rating is 'A-3'. Liquidity is adequate. Pinnacle West has $18 million of cash and cash equivalents, and total credit facilities of nearly $1.4 billion, with approximately $943 million available as of March 31, 2008. In October 2007, APS received approval from ACC to increase its authorized short-term debt borrowing capacity by $500 million, and long-term debt borrowing capacity by $1 billion. This will help address the needs of its growing customer base, and the increasing requirement for natural gas and purchased power.

Pinnacle West had close to $185 million available under its $300 million unsecured revolving credit facility that expires in December 2010. APS had $682 million available under its two unsecured revolving credit facilities, $400 million of which expires in December 2010, and $500 million in September 2011. SunCor has two credit facilities expiring in October and December 2008 that total $170 million and approximately $76 million, respectively, available as of September 2007.

Discretionary cash flow is expected to be negative for 2008 due to APS' capital expenditure plans. Excluding the remarketing of APS' pollution control debt, neither PWCC nor APS has any significant debt obligations maturing until 2011.

Outlook

The stable outlook reflects our expectation that consolidated cash flow volatility has been tamped down by the ACC's approval of a stronger PSA that speeds the recovery of fuel costs, but consolidated financial performance will continue to be challenged by regulatory lag at APS, which could be moderated by APS' pending interim rate request. The stable outlook is premised on no meaningful adverse changes in the company's business risks and continued financial performance that is not significantly weaker than 2007 results. Equity issuances will be expected to balance the capital structure of the company as APS continues to invest heavily in infrastructure. Ratings could be lowered to speculative grade if the company is not able to overcome the challenge of ensuring timely recovery of its prudently incurred costs through rate increases approved by the ACC. Given these challenges, and that presented by NRC scrutiny of Palo Verde, we see little potential for positive movement in the ratings or outlook.

STANDARD & POOR'S

RatingsDirect®

June 25, 2008

Arizona Public Service Co.

Primary Credit Analyst:
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Table Of Contents

Arizona Public Service Co.

Major Rating Factors

Corporate Credit Rating

BBB-/Stable/A-3

Strengths:

- A favorable power supply adjuster (PSA) that while capped at 4 mils per kilowatt-hour (kWh) is benched to projected power prices, which should minimize fuel and purchased power deferral balances going forward;
- Declining legacy deferral balances, reflecting the recovery through surcharges of past fuel and purchased power costs from retail ratepayers;
- An attractive service territory, which while currently weakened by a real estate cycle that is depressing new customer connections, nevertheless is expected to experience above-average growth over the long run;
- A balance power supply portfolio that is a mixture of coal, nuclear, and gas generation and purchases; due to a self-build moratorium in place until 2015, Arizona Public Service (APS) is expected to increasingly rely on gas-fired purchases, which underlines the importance of a strong PSA;
- Stabilized operations at Palo Verde, although the nuclear units remain under heightened Nuclear Regulatory Commission (NRC) scrutiny; APS operates the plant and owns a 29.1% share of the plant; and
- A manageable maturity schedule for both the parent and the utility until 2011 when about $578 million is due on a consolidated basis.

Weaknesses:

- The consolidated financial profile of the company is unlikely to meaningfully improve for the foreseeable future due to APS' heavy capital investment, coupled with a lagged regulatory process in Arizona;
- Continued tension in the relationship between APS and the Arizona Corporation Commission (ACC), which is particularly unfavorable for credit quality due to the company's ongoing need for rate relief;
- APS' re-filing of its 2008 general rate case based on a revised test year is expected to delay rate relief past the summer of 2009, which will, all else equal, weaken cash flow measures;
- Consolidated free operating cash flows are expected to be negative through at least 2010, based on the company's capital spending program; and
- SunCor's near-term prospects to make distributions to its parent are limited, due a depressed real estate cycle, which has hit the southwest especially hard.

Rationale

Standard & Poor's Ratings Services today affirmed the 'BBB-' corporate credit rating assigned to Pinnacle West Capital Corporation (PWCC) and its utility, Arizona Public Service. The outlook is stable. The consolidated credit ratings of PWCC primarily reflect the operations of its largest subsidiary, APS, a regulated, electric utility serving about 1.1 million customers within its service territory, which spans roughly two-thirds of Arizona and includes about half of the Phoenix MSA. We view the business profile of PWCC and APS to be 'strong'. While the company continues to benefit from a number of favorable attributes including a good service territory, a reasonably balanced

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	--Average of past three fiscal years--				
(Mil. $)					
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Debt and equity	7,786.0	5,642.4	2,223.5	2,479.0	4,249.3
Adjusted ratios					
EBIT interest coverage (x)	2.8	2.0	1.8	1.7	1.7
FFO int. cov. (X)	3.6	2.9	2.7	2.8	2.7
FFO/debt (%)	15.5	13.2	13.6	15.4	10.5
Discretionary cash flow/debt (%)	(8.2)	(13.4)	(1.7)	2.1	(5.7)
Net cash flow / capex (%)	62.2	46.9	81.0	113.0	65.2
Total debt/debt plus equity (%)	56.8	59.3	61.6	74.2	63.2
Return on common equity (%)	6.8	7.2	5.7	8.3	5.4
Common dividend payout ratio (un-adj.) (%)	75.5	60.4	54.7	50.4	72.9

*Fully adjusted (including postretirement obligations).

Table 2

Pinnacle West Capital Corp. -- Financial Summary*

Industry Sector: Electric

	--Fiscal year ended Dec. 31--				
	2007	**2006**	**2005**	**2004**	**2003**
Rating history	BBB-/Stable/A-3	BBB-/Stable/A-3	BBB-/Stable/A-3	BBB/Negative/A-2	BBB/Stable/A-2
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Debt	4,686.5	4,358.6	4,214.6	4,272.8	4,120.9
Preferred stock	0.0	0.0	0.0	0.0	0.0
Equity	3,531.6	3,446.1	3,120.5	2,653.7	2,510.0
Debt and equity	8,218.1	7,804.7	7,335.1	6,926.5	6,630.8
Adjusted ratios					
EBIT interest coverage (x)	2.7	3.0	2.6	2.6	2.2
FFO int. cov. (x)	3.7	3.8	3.3	3.2	4.2
FFO/debt (%)	15.7	16.9	13.8	13.3	22.6
Discretionary cash flow/debt (%)	(10.1)	(12.5)	(1.7)	2.6	1.0
Net cash flow / capex (%)	56.2	72.0	59.7	67.7	108.6
Debt/debt and equity (%)	57.0	55.8	57.5	61.7	62.1
Return on common equity (%)	7.3	8.2	4.8	7.7	7.1
Common dividend payout ratio (un-adj.) (%)	70.4	63.4	105.9	68.6	65.4

*Fully adjusted (including postretirement obligations).

Table 3

Reconciliation Of Pinnacle West Capital Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*

	--Fiscal year ended Dec. 31, 2007--							
Pinnacle West Capital Corp. reported amounts								
	Debt	**Operating income (before D&A)**	**Operating income (before D&A)**	**Operating income (after D&A)**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Capital expenditures**
Reported	3,631.6	992.7	992.7	619.3	189.6	649.6	649.6	941.6
Standard & Poor's adjustments								
Operating leases	432.2	79.0	27.7	27.7	27.7	51.3	51.3	15.4
Postretirement benefit obligations	329.7	12.8	12.8	12.8	--	8.7	8.7	--
Capitalized interest	--	--	--	--	23.1	(23.1)	(23.1)	(23.1)
Share-based compensation expense	--	--	6.0	--	--	--	--	--
Power purchase agreements	293.0	21.1	21.1	18.1	18.1	3.0	3.0	--

Table 3

Reconciliation Of Pinnacle West Capital Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*(cont.)

Reclassification of nonoperating income (expenses)	--	--	--	20.0	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	66.6	--
US decommissioning fund contributions	--	--	--	--	--	(20.7)	(20.7)	--
Total adjustments	1,054.9	112.8	67.6	78.6	68.9	19.2	85.8	(7.7)

Standard & Poor's adjusted amounts

	Debt	Operating income (before D&A)	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Capital expenditures
Adjusted	4,686.5	1,105.5	1,060.2	697.8	258.4	668.8	735.3	933.9

*Pinnacle West Capital Corp. reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts.

Ratings Detail (As Of June 25, 2008)*	
Arizona Public Service Co.	
Corporate Credit Rating	BBB-/Stable/A-3
Commercial Paper	
Local Currency	A-3
Senior Unsecured	
Local Currency	BBB-
Corporate Credit Ratings History	
21-Dec-2005	BBB-/Stable/A-3
01-Apr-2005	BBB/Stable/A-2
19-Mar-2004	BBB/Negative/A-2
Related Entities	
Pinnacle West Capital Corp.	
Issuer Credit Rating	BBB-/Stable/A-3
Commercial Paper	
Local Currency	A-3
Senior Unsecured	
Local Currency	BB+
PVNGS II Funding Corp. Inc.	
Issuer Credit Rating	BBB-/Stable/--
Senior Unsecured	
Local Currency	BBB-

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

STANDARD & POOR'S

RatingsDirect®

June 25, 2008

Pinnacle West Capital Corp.

Primary Credit Analyst:
Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

Table Of Contents

Pinnacle West Capital Corp.

Major Rating Factors

Corporate Credit Rating

BBB-/Stable/A-3

Strengths:

- A favorable power supply adjuster (PSA) that while capped at 4 mils per kilowatt-hour (kWh) is benched to projected power prices, which should minimize fuel and purchased power deferral balances going forward;
- Declining legacy deferral balances, reflecting the recovery through surcharges of past fuel and purchased power costs from retail ratepayers;
- An attractive service territory, which while currently weakened by a real estate cycle that is depressing new customer connections, nevertheless is expected to experience above-average growth over the long run;
- A balance power supply portfolio that is a mixture of coal, nuclear, and gas generation and purchases; due to a self-build moratorium in place until 2015, Arizona Public Service (APS) is expected to increasingly rely on gas-fired purchases, which underlines the importance of a strong PSA;
- Stabilized operations at Palo Verde, although the nuclear units remain under heightened Nuclear Regulatory Commission (NRC) scrutiny; APS operates the plant and owns a 29.1% share of the plant; and
- A manageable maturity schedule for both the parent and the utility until 2011 when about $578 million is due on a consolidated basis.

Weaknesses:

- The consolidated financial profile of the company is unlikely to meaningfully improve for the foreseeable future due to APS' heavy capital investment, coupled with a lagged regulatory process in Arizona;
- Continued tension in the relationship between APS and the Arizona Corporation Commission (ACC), which is particularly unfavorable for credit quality due to the company's ongoing need for rate relief;
- APS' re-filing of its 2008 general rate case based on a revised test year is expected to delay rate relief past the summer of 2009, which will, all else equal, weaken cash flow measures;
- Consolidated free operating cash flows are expected to be negative through at least 2010, based on the company's capital spending program; and
- SunCor's near-term prospects to make distributions to its parent are limited, due a depressed real estate cycle, which has hit the southwest especially hard.

Rationale

Standard & Poor's Ratings Services today affirmed the 'BBB-' corporate credit rating assigned to Pinnacle West Capital Corporation (PWCC) and its utility, Arizona Public Service. The outlook is stable. The consolidated credit ratings of PWCC primarily reflect the operations of its largest subsidiary, APS, a regulated, electric utility serving about 1.1 million customers within its service territory, which spans roughly two-thirds of Arizona and includes about half of the Phoenix MSA. We view the business profile of PWCC and APS to be 'strong'. While the company continues to benefit from a number of favorable attributes including a good service territory, a reasonably balanced

power supply portfolio and a good PSA. However, APS' continues to face significant regulatory challenges.

APS provided the company with about 92% of its consolidated net income in 2007. SunCor, PWCC's real estate development company, provided about 4%, but due to the significant real estate slowdown in the southwest, it is unlikely it will be a meaningful contributor of cash flows or income over the next several years. (Prior to the real estate downturn, our forecasts have conservatively limited earnings from this subsidiary due to the cyclic nature of its cash flows.) Other subsidiary operations include Pinnacle West Trading and Marketing, which contributed about 4% of consolidated net income in 2007. This subsidiary has since last year been minimizing trading operations. Its largest contract was serving all-requirements load for UNS Electric Inc., which ended in May 2008.

We view the financial profile of PWCC and APS to be 'aggressive', which reflects: year-end debt to total capitalization of 57% (adjusted for items such as power purchases and operating leases); heavy capital spending that is expected to drive negative free operating cash flow for the foreseeable future; cash flow weakness as a function of protracted rate cases; and, while modest, the presence of unregulated activities, which can be unpredictable in their earnings contributions.

Because the preponderance of cash flows for consolidated operations stems from APS, we expect financial performance will continue to be heavily dependent on regulatory outcomes. The conclusion of APS' last general rate case in June 2007 (filed in November 2005 and revised in early 2006) provided the company with mechanisms to recover legacy deferrals and speed the recovery of fuel costs going forward. This rate relief, in place for the last half of 2007, assisted the company in maintaining credit metrics roughly in line with past performance. Funds from operations (FFO) to total debt was about 16% at year-end, with FFO interest coverage around 4x. On a trailing 12-month basis the company's performance has been slightly above these levels, due in part to the federal tax stimulus package approved by the U.S. Congress earlier this year, which is expected to increase deferred taxes (which are added back to FFO and thus increase this total).

We expect APS to be in more or less continuous rate case mode for the next few years. Given APS' capital spending program, forecasted to be about $1.1 billion annually through 2010, the utility will need to file regular general rate cases to manage recovery of its investment. The use of a historical test year in Arizona, coupled with the fact that fully litigated rate cases take between 18 to 24 months to complete, is expected to result in no meaningful improvement in financial performance through 2009 and possibly beyond, depending on the timing and the outcome of the company's current case.

APS filed its current rate case in March 2008. ACC staff requested that the company revise its filing to reflect a test year ending Dec. 31, 2007 (as opposed to the originally filed version based on a Sept. 30, 2007, test year). The revised case has not been officially certified by the ACC, but certification is expected by July 2. Unlike the company's last rate case, in which $315 million of the $322 million of rate relief granted was for fuel and power-related costs, the majority of the current case is for nonfuel expenditures.

While the revised case increased the company's request to $278 million (about an 8.5% increase, excluding the company's request that customers be assessed about $53 million in impact fees), the re-filing means that is unlikely the ACC will reach an outcome in the case before October 2009, and because the majority of APS' sales occur in the summer months, the company's financial performance could weaken in 2009.

This month, the company requested that the ACC allow it to continue to collect a $0.004/kWh charge that it has been collecting in 2007 to recover legacy purchased power and fuel deferrals. Given that the portion of deferred

costs associated with this surcharge is due to be paid by July or August, APS has asked that the ACC continue the charge, but authorize collection as an interim base rate increase, subject to refund as part of the resolution of its rate case, expected in fall 2009. (Last year, the ACC approved similar relief for Tucson Electric Power in its pending rate case settlement when it granted the southern Arizona utility the opportunity to continue to collect charges related to a competitive transition charge, or CTC, while its rate case is pending.) While retail customers would essentially see no rate increase because APS is asking to continue the surcharge as an interim increase, it is unclear what action the ACC will take. A vote could occur as early as late summer.

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Preferred stock	0.0	0.0	0.0	0.0	0.0
Equity	3,531.6	3,446.1	3,120.5	2,653.7	2,510.0
Debt and equity	8,218.1	7,804.7	7,335.1	6,926.5	6,630.8
Adjusted ratios					
EBIT interest coverage (x)	2.7	3.0	2.6	2.6	2.2
FFO int. cov. (x)	3.7	3.8	3.3	3.2	4.2
FFO/debt (%)	15.7	16.9	13.8	13.3	22.6
Discretionary cash flow/debt (%)	(10.1)	(12.5)	(1.7)	2.6	1.0
Net cash Flow / capex (%)	56.2	72.0	59.7	67.7	108.6
Debt/debt and equity (%)	57.0	55.8	57.5	61.7	62.1
Return on common equity (%)	7.3	8.2	4.8	7.7	7.1
Common dividend payout ratio (un-adj.) (%)	70.4	63.4	105.9	68.6	65.4

*Fully adjusted (including postretirement obligations).

Table 3

Reconciliation Of Pinnacle West Capital Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*

	--Fiscal year ended Dec. 31, 2007--							
Pinnacle West Capital Corp. reported amounts								
	Debt	**Operating income (before D&A)**	**Operating income (before D&A)**	**Operating income (after D&A)**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Capital expenditures**
Reported	3,631.6	992.7	992.7	619.3	189.6	649.6	649.6	941.6
Standard & Poor's adjustments								
Operating leases	432.2	79.0	27.7	27.7	27.7	51.3	51.3	15.4
Postretirement benefit obligations	329.7	12.8	12.8	12.8	--	8.7	8.7	--
Capitalized interest	--	--	--	--	23.1	(23.1)	(23.1)	(23.1)
Share-based compensation expense	--	--	6.0	--	--	--	--	--
Power purchase agreements	293.0	21.1	21.1	18.1	18.1	3.0	3.0	--

Table 3

Reconciliation Of Pinnacle West Capital Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*(cont.)

Reclassification of nonoperating income (expenses)	--	--	--	20.0	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	66.6	--
US decommissioning fund contributions	--	--	--	--	--	(20.7)	(20.7)	--
Total adjustments	1,054.9	112.8	67.6	78.6	68.9	19.2	85.8	(7.7)

Standard & Poor's adjusted amounts

	Debt	Operating income (before D&A)	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Capital expenditures
Adjusted	4,686.5	1,105.5	1,060.2	697.8	258.4	668.8	735.3	933.9

*Pinnacle West Capital Corp. reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts.

Ratings Detail (As Of June 25, 2008)*

Pinnacle West Capital Corp.	
Corporate Credit Rating	BBB-/Stable/A-3
Commercial Paper	
Local Currency	A-3
Senior Unsecured	
Local Currency	BB+
Corporate Credit Ratings History	
21-Dec-2005	BBB-/Stable/A-3
01-Apr-2005	BBB/Stable/A-2
19-Mar-2004	BBB/Negative/A-2
Related Entities	
Arizona Public Service Co.	
Issuer Credit Rating	BBB-/Stable/A-3
Commercial Paper	
Local Currency	A-3
Senior Unsecured	
Local Currency	BBB-
PVNGS II Funding Corp. Inc.	
Issuer Credit Rating	BBB-/Stable/--
Senior Unsecured	
Local Currency	BBB-

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

STANDARD & POOR'S

RATINGSDIRECT®

February 22, 2007

Bulletin:

Nuclear Regulatory Comm. Ruling Adverse To Arizona Public Service's Credit; Rating Unchanged

Primary Credit Analyst:
Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

SAN FRANCISCO (Standard & Poor's) Feb. 22, 2007--Standard & Poor's Ratings Services said today that the Nuclear Regulatory Commission's (NRC) ruling assigning a "white" safety violation to Palo Verde Unit 3 is adverse for the credit quality of its operator, Arizona Public Service (BBB-/Stable/A-3), but was expected.

The finding completes an investigation in which the NRC questioned the procedures and maintenance standards for the plant's emergency diesel generators. While the NRC could have issued a more severe ruling, its finding announced today places the nearly 4,000 MW nuclear generating station in the "multiple/repetitive degraded cornerstone" column of its performance matrix. This cornerstone is the fourth-worst of five categories assigned.

The designation will trigger heightened NRC oversight and inspections, which will increase costs for the owners of the plant. These costs are likely to be manageable. Our greater concern is that this increased NRC scrutiny could result in plant production to be curtailed to comply with NRC inspections or as a result of additional findings. Replacement power purchases associated with recent Palo Verde outages have been costly for the company and must be approved for recovery by the Arizona Corporation Commission.

For further information on this subject, see our recent commentary, More

NRC Oversight At The Palo Verde Plant Could Generate Problems For APS, published Jan. 16, 2007 on RatingsDirect.

STANDARD
&POOR'S

RATINGSDIRECT®

January 16, 2007

Summary:
Arizona Public Service Company, Arizona

Primary Credit Analyst:
Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

Table Of Contents

Summary:

Arizona Public Service Company, Arizona

Credit Rating: BBB-/Stable/A-3

Rationale

Arizona Public Service's (APS) 'BBB-' corporate credit rating is based on the consolidated credit quality of Pinnacle West Capital Corp. (PWCC), of which APS is the principal subsidiary. PWCC and APS' satisfactory business profile score of '6' (on a 10-point scale, where '10' represents the highest risk) reflects the uncertainty concerning how the Arizona Corporation Commission (ACC) will address APS' pending general rate case request and operational performance at its Palo Verde nuclear station.

As expected, consolidated cash flows have remained weak for the rating but have stabilized on a trailing twelve-month (TTM) basis ending Sept. 30, 2006. Modest improvement has been largely due to temporary rate relief provided to APS. At Sept. 30, TTM consolidated funds from operations was approximately $666 million, relative to a low of $486 million on a TTM basis ending March 2006, when the company's financial position was rapidly deteriorating due principally to a mismatch between the revenues the company is authorized to collect in base retail electric rates and its fuel and purchased power costs. (The generation component of APS rates, last adjusted in 2003, is about 2.047 cents per kilowatt-hour (kWh) and its power supply adjuster (PSA) is capped at 4 mills per kWh.)

In response, the ACC granted approximately 9% in interim relief, including a 7 mill/kWh surcharge effective May 1, 2006, which boosted rates by about 8.3% beginning May 1, 2006. TTM ending Sept. 30 funds from operations (FFO) to total debt is now approximately 14.5%, and FFO interest coverage was 3.7x, a slight improvement from 2005 levels, but FFO to total debt remains very weak for the rating. An attenuation in gas prices has also assisted the company in recouping ground on its cash flow metrics. (Roughly one-third of APS system requirements are met with natural gas-based contracts or generation, and in 2006 about 15% of natural gas exposure was unhedged.) On December 8, 2006, the ACC favorably extended the 7 mill surcharge, which was due to expire in January 2007, until APS' rate case is resolved, lending some expected stability to APS' cash flows and credit metrics while a decision is pending.

Deferral balances remain an ongoing credit issue, but are in line with our expectations and have not grown materially relative to a 2005 year-end position of $173 million. As of Sept. 30, 2006, APS had about $209 million on its balance sheet in deferred fuel and purchased power costs. On a cash flow basis, for the nine months ending Sept. 30, the company incurred $231 million in deferrals, but it also it collected in surcharges about $195 million, for a net increase in the deferred balance of about $36 million. (In contrast, in 2005, the company rapidly incurred deferrals without any offsetting surcharge.) In the fourth quarter of 2006, mild weather and lower costs to meet the shoulder season are expected to result in amortization of deferrals balances to exceed new accumulations, and year-end 2006 deferrals balances are expected to be at about 2005 levels.

PWCC's consolidated TTM debt to total capitalization was around 60% as of Sept. 30, 2006, and adjusted for power purchase obligations and operating leases (and including APS' sizable pension obligations), higher than in 2005 in large part due to APS' issuance of $400 million in debt last August. This ratio is expected to be somewhat strained, as heavy capital expenditures that average $900 million per year 2007-2009 will trigger additional new borrowings.

Any long-term improvement in consolidated credit metrics is premised on the outcome of APS' current rate case. The company is seeking a $434 million (20%) rate increase. (APS modestly lowered its request in October 2006.) Given that the 7 mill/kWh surcharge will be in place until any rate adjustments are approved as part of the general rate case, the company's revised request is about 12% above current rates. Staff testimony supports instead a 9.8% increase, or $208 million.

The case should be resolved by mid-2007.

Palo Verde 1 returned to service in mid-July 2006 following an extended outage to repair vibration problems on a cooling line, with the capacity factor for all three units at 88% through Sept. 30, 2006. APS is facing the potential for increased regulatory oversight by the Nuclear Regulatory Commission, which is expected to issue sometime in March a ruling on whether problems with the plant's emergency diesel generators are a violation that compromises public safety. An adverse finding would move Palo Verde into a lower-performing category, which would trigger additional oversight. This could become a credit concern if increased scrutiny and special inspections cause a decrease in the plant's output.

Short-term credit factors

PWCC and APS' short-term rating is 'A-3'. Consolidated liquidity improved with the addition of a $500 million revolving credit facility that will terminate in 2011. The facility can be increased to $600 million upon the fulfillment of certain conditions and augments APS' existing revolving credit line of $400 million available to support the issuance of up to $250 million in CP or for borrowing or LOCs. The line matures in December 2010. PWCC has a $300 million credit facility that supports the issuance of up to $250 million of CP or for bank borrowings, including LOCs. The facility expires in December 2010.

Consolidated short-term borrowings were $57 million as of Sept. 30, 2006. The additional APS line bolsters what had been some potential for weakness under adverse market and credit event stress tests. Liquidity adequacy for both a credit and combined credit and market stress are now well more than 1.0x.

Consolidated cash and investments stood at $128 million at Sept. 30, 2006, relative to year-end cash balances of $154 million at Dec. 31, 2005.

APS has hedged 85% of its 2007 power and gas requirements, which provides some protection against further escalation in fuel and purchased power costs. Consolidated capital expenditures continue to be large, due to significant growth in APS' service area, and are estimated at about $890 million for 2006.

Outlook

The stable outlook for PWCC and APS' rating is premised on whether APS receives a general rate case outcome that allows the company to maintain consolidated credit metrics that are in line with the rating, which will be the primary factor in whether future cash flow metrics are restored to levels in line with the rating. A negative rating change or outlook could also result if the size of the deferred balances materially increases, as a result of Palo Verde's performance or other factors. Given the uncertainty over the rate case outcome and the potential for continued operational challenges at Palo Verde, there is little opportunity for a positive rating action at this time;

however, ACC's actions have clearly stabilized, for now, the company's financial position.

The McGraw-Hill Companies

STANDARD &POOR'S

RATINGSDIRECT®

January 16, 2007

Report Discusses Oversight Implications For Palo Verde Plant And Arizona Public Service Co.

Primary Credit Analyst:
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Media Contact:
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SAN FRANCISCO (Standard & Poor's) Jan. 16, 2007--Palo Verde Nuclear Generating Station, the largest U.S. nuclear power plant, has experienced a number of operational and regulatory issues since 2004. Recent events may increase Nuclear Regulatory Commission (NRC) oversight, which could hold credit implications for Arizona Public Service Co. (APS; BBB-/Stable/A-3), Palo Verde's operator and largest owner. In an article published today, Standard & Poor's Ratings Services examines what would lead to increased NRC scrutiny of the nuclear plant, as well as the operational and financial impact this could have on APS and its parent, Pinnacle West Capital Corp. (BBB-/Stable/A-3).

The report, "More NRC Oversight At The Palo Verde Plant Could Generate Problems For APS," outlines the three key challenges that APS, as Palo Verde's operator, faces in 2007: restoring the plant's operational performance, regaining its reputation with the NRC, and recovering in authorized rates the majority of replacement power costs associated with Palo Verde's 2005 and 2006 unplanned outages.

If the NRC does step up its regulatory requirements for Palo Verde, the plant will be ranked among the poorest complying nuclear facilities in the U.S.

"APS is at a critical juncture with its regulatory relationship with the NRC," said Standard & Poor's credit analyst Anne Selting. "Today, the NRC is holding hearings in Texas to discuss concerns related to the performance of one of the plant's emergency diesel generators, and a ruling is expected to follow shortly," she noted. "While escalated NRC regulation does not necessarily equate to an immediate erosion in credit quality, heightened oversight will increase costs and could even potentially lead to replacement power purchases in 2007."

The report is available to subscribers of RatingsDirect, the real-time Web-based source for Standard & Poor's credit ratings, research, and risk analysis, at www.ratingsdirect.com. If you are not a RatingsDirect subscriber, you may purchase a copy of the report by calling (1) 212-438-9823 or sending an e-mail to research_request@standardandpoors.com. Ratings information can also be found on Standard & Poor's public Web site at www.standardandpoors.com; under Credit Ratings in the left navigation bar, select Find a Rating, then Credit Ratings Search. Members of the media may request a copy of this report by contacting the media representative provided.

STANDARD
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RATINGSDIRECT®

January 16, 2007

Summary:

Pinnacle West Capital Corp., Arizona

Primary Credit Analyst:
Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

Table Of Contents

Summary:
Pinnacle West Capital Corp., Arizona

Credit Rating: BBB-/Stable/A-3

Rationale

The consolidated 'BBB-' corporate credit rating on Pinnacle West Capital Corp. (PWCC) is based almost entirely on the credit strength of its largest holding, Arizona Public Service Co. (APS), which contributed about 73% of 2005 consolidated income from continuing operations. APS provides retail electric service to about 1 million customers within a service territory that includes much of Arizona and roughly half of the Phoenix MSA. PWCC also owns three unregulated subsidiaries--SunCor, El Dorado Investment Co., and APS Energy Services (Pinnacle West Energy was recently merged into PWCC and no longer exists as an entity). Due to the company's reduction in these diversified business interests, only SunCor's operations are material to credit quality, contributing about 17% of 2005 income from continuing operations. The remaining 10% of consolidated income from continuing operations is composed predominately of wholesale marketing and trading at both PWCC and APS.

PWCC and APS' satisfactory business profile score of '6' (on a 10-point scale where '10' represents the highest risk) reflects the uncertainty concerning how the Arizona Corporation Commission (ACC) will address APS' pending general rate case request and operational performance at the Palo Verde nuclear station, which APS operates and owns a 29% stake in.

As expected, consolidated cash flows remain weak for the rating but have stabilized on a trailing twelve-month (TTM) basis ending Sept. 30, 2006. Modest improvement has been largely due to temporary rate relief provided to APS. At Sept. 30, TTM consolidated funds from operations was approximately $666 million, relative to a low of $486 million on a TTM basis ending March 2006, when the company's financial position was rapidly deteriorating due principally to a mismatch between the revenues the company is authorized to collect in base retail electric rates and its fuel and purchased power costs. (The generation component of APS rates, last adjusted in 2003, is about 2.047 cents per kilowatt-hour(kWh) and its power supply adjuster (PSA) is capped at 4 mills per kWh.)

In response, the ACC granted approximately 9% in interim relief, including a 7 mill/kWh surcharge effective May 1, 2006, which boosted rates by about 8.3% beginning May 1, 2006. TTM ending Sept. 30 funds from operations (FFO) to total debt is now approximately 14.5%, and FFO interest coverage was 3.7x, a slight improvement from 2005 levels, but FFO to total debt remains very weak for the rating. An attenuation in gas prices has also assisted the company in recouping ground on its cash flow metrics. (Roughly one-third of APS system requirements are met with natural gas based contracts or generation, and in 2006 about 15% of natural gas exposure was unhedged.) On December 8, 2006 the ACC favorably extended the 7 mill surcharge, which was due to expire in January 2007, until APS' rate case is resolved, lending some expected stability to APS' cash flows and credit metrics while a decision is pending.

Deferral balances, remain an ongoing credit issue, but are in line with our expectations and have not grown materially relative to a 2005 year-end position of $173 million. As of Sept. 30, 2006, APS had about $209 in deferred fuel and purchased power costs. On a cash flow basis, for the nine months ending Sept. 30, the company incurred $231 million in deferrals, but it also it collected in surcharges about $195 million, for a net increase in the deferred balance of about $36 million. (In contrast, in 2005, the company rapidly incurred deferrals without any offsetting surcharge.) In the fourth quarter of 2006, mild weather and lower costs to meet the shoulder season are expected to result in amortization of deferrals balances to exceed new accumulations, and year-end 2006 deferrals balances are expected to be at about 2005 levels.

PWCC's consolidated TTM debt to total capitalization was around 60% at Sept. 30, 2006 (adjusted for power purchase obligations and operating leases (and including APS' sizable pension obligations), higher than in 2005 in large part due to APS' issuance of $400 million in debt last August. This ratio is expected to be somewhat strained, as heavy capital expenditures that average $900 million per year 2007-2009 will trigger additional new borrowings.

Any long-term improvement in consolidated credit metrics is premised on the outcome of APS' current rate case. The company is seeking a $434 million (20%) rate increase. (APS modestly lowered its request in October 2006.) Given that the 7 mill/kWh surcharge will be in place until any rate adjustments are approved as part of the general rate case, the company's revised request is about 12% above current rates. Staff testimony supports instead a 9.8% increase, or $208 million.

The case should be resolved by mid-2007.

Palo Verde 1 returned to service in mid-July 2006 following an extended outage to repair vibration problems on a cooling line, with the capacity factor for all three units at 88% through Sept. 30, 2006. APS is facing the potential for increased regulatory oversight by the Nuclear Regulatory Commission, which is expected to issue sometime in March a ruling on whether problems with the plant's emergency diesel generators are a violation that compromises public safety. An adverse finding would move Palo Verde into a lower-performing category, which would trigger additional oversight. This could become a credit concern if increased scrutiny and special inspections cause a decrease in the plant's output.

Short-term credit factors

PWCC and APS' short-term rating is 'A-3'. Consolidated liquidity improved with the addition of a $500 million revolving credit facility that will terminate in 2011. The facility can be increased to $600 million upon the fulfillment of certain conditions and augments APS' existing revolving credit line of $400 million available to support the issuance of up to $250 million in CP or for borrowing or LOCs. The line matures in December 2010. PWCC has a $300 million credit facility that supports the issuance of up to $250 million of CP or for bank borrowings, including LOCs. The facility expires in December 2010.

Consolidated short-term borrowings were $57 million as of Sept. 30, 2006. The additional APS line bolsters what had been some potential for weakness under adverse market and credit event stress tests. Liquidity adequacy for both a credit and combined credit and market stress are now well more than1.0x.

Consolidated cash and investments stood at $128 million at Sept. 30, 2006, relative to year-end cash balances of $154 million at Dec. 31, 2005.

APS has hedged 85% of its 2007 power and gas requirements, which provides some protection against further escalation in fuel and purchased power costs. Consolidated capital expenditures continue to be large, due to significant growth in APS' service area, and are estimated at about $890 million for 2006, which the company expects it will meet.

Outlook

The stable outlook for PWCC and APS' rating is premised on whether APS receives a general rate case outcome that allows the company to maintain consolidated credit metrics that are in line with the rating, which will be the primary factor in whether future cash flow metrics are restored to levels in line with the rating. A negative rating change or outlook could also result if the size of the deferred balances materially increases, as a result of Palo Verde's performance or other factors. Given the uncertainty over the rate case outcome and the potential for continued operational challenges at Palo Verde, there is little opportunity for a positive rating action at this time; however, ACC' actions have clearly stabilized, for now, the company's financial position.

Moody's Investors Service

Global Credit Research
Credit Opinion
28 JUL 2008

Credit Opinion: Pinnacle West Capital Corporation

Pinnacle West Capital Corporation

United States

Ratings

Category	**Moody's Rating**
Outlook	Stable
Issuer Rating	Baa3
Sr Unsec Bank Credit Facility	Baa3
Senior Unsecured Shelf	(P)Baa3
Subordinate Shelf	(P)Ba1
Preferred Shelf	(P)Ba2
Commercial Paper	P-3
Arizona Public Service Company	
Outlook	Stable
Issuer Rating	Baa2
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Subordinate Shelf	(P)Baa3
Commercial Paper	P-2

Contacts

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Key Indicators

Pinnacle West Capital Corporation

ACTUALS	**1Q08 LTM**	**2007**	**2006**	**2005**
(CFO Pre-W/C + Interest) / Interest Expense [1][2]	**4.0x**	**3.9x**	**4.2x**	**3.7x**
(CFO Pre-W/C) / Debt [2]	**17.5%**	**17.2%**	**18.9%**	**16.4%**
(CFO Pre-W/C - Dividends) / Debt [2]	**12.8%**	**12.5%**	**14.1%**	**11.8%**
(CFO Pre-W/C - Dividends) / Capex [2]	**57.3%**	**57.6%**	**75.2%**	**69.6%**
Debt / Book Capitalization	**48.9%**	**48.5%**	**47.4%**	**48.0%**
EBITA Margin	**19.2%**	**20.2%**	**21.6%**	**18.9%**

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items [2] Changes in risk management and trading assets and liabilities are excluded from CFO Pre-W/C

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Corporate Profile

Pinnacle West Capital Corporation (Pinnacle: Baa3 senior unsecured, stable) is a holding company whose principal subsidiary, Arizona Public Service Corporation (APS: Baa2 senior unsecured, stable), is a vertically integrated electric utility that provides electric service to most of the state of Arizona with the major exceptions of about one-half of the Phoenix metropolitan area and the Tucson metropolitan area. Pinnacle's other subsidiaries are engaged in the sale of energy related products and services and the development of residential and commercial real estate.

Recent Events

On July 25, 2008 Moody's revised the outlooks for APS and Pinnacle to stable from negative. The revision in outlook was a result of the companies' stable financial performance and also reflects our opinion of APS' improved prospects for more timely recovery of certain costs than had historically been the case. Our view is based on recent regulatory decisions involving recovery mechanisms for the cost of fuel and purchased power and transmission as well as recovery mechanisms for certain growth related costs. The outlook revision also recognized APS' demonstrated intent to attempt to minimize regulatory lag by filing for additional rate relief as soon as practicable.

Regulatory Activity

Approval of Line Extension Fees

In February 2008 the Arizona Corporation Commission (ACC) approved an amendment to APS' line extension schedule which eliminated certain free footage allowances and permitted APS to collect, on a current basis, costs relating to line extensions, which are estimated to be approximately $3,500 - $5,000 per new meter set (pre-tax). Moody's views the incremental (after-tax) cash flow resulting from these fees as recurring, and we have adjusted our credit metrics to reflect them as operating cash flows.

General Rate Case Filing

In June 2008, APS filed for a $278.2 million net rate increase (approximately 8.5% from existing customers) comprised of a $264.3 million non-fuel related increase and a $13.9 million net fuel-related increase. APS has proposed to collect up to $53 million of the increase specifically from new customers. The fuel increase request is net of approximately $170 million currently being collected in APS rates through its power supply adjustor (PSA) mechanism. APS' June filing is based on a test year ended December 2007. The request has been accepted by ACC Staff. A procedural schedule has been proposed with hearings in April 2009 and a decision expected in the latter part of 2009.

Request for Interim Increase

Also in June 2008, APS filed a request for an interim base rate increase of $.003987 per kWh to become effective upon the expiration of the $.003987 per kWh power supply adjustor surcharge currently in APS' rates. APS estimates the current surcharge will remain in effect through July. A procedural schedule has been set for this request, with hearings scheduled for September 2008 and a decision anticipated shortly thereafter.

Palo Verde

In February 2007, Nuclear Regulatory Commission (NRC) placed Palo Verde Unit 3 (PVU3), into the "multiple/repetitive degraded cornerstone" column of the NRC's action matrix, which has resulted in an enhanced inspection regimen and some increased operating costs for APS as it seeks to improve its processes at all three Palo Verde units. In February 2008, the NRC issued its revised confirmatory action letter, and as required, on March 31, 2008, APS submitted its revised improvement plan. The NRC will continue to provide increased oversight at Palo Verde until the facility has demonstrated sustained performance improvement. APS anticipates that this process will continue into 2009.

While operating performance at Palo Verde has improved, capacity factors continue to be impacted by planned outages (including a steam generator replacement in 2007) that have been extended by additional inspections. In 2007, the plant's average capacity factor was 79.0% versus 70.7% in 2006 and 77.4% in 2005. For the first quarter of 2008, the nuclear capacity factor was 93%.

Rating Rationale

The Baa3 rating for the senior unsecured obligations of Pinnacle reflects the stability of its regulated cash flows,

APS13052
Page 2 of 6

the economic health of APS' service territory, its regulatory environment, cash flow credit metrics that are appropriate for the rating, and its modest exposure to a currently weak real estate market. The rating and outlook consider the traditionally challenging regulatory environment in Arizona, but also contemplates recent ACC decisions and regulatory activities that appear intended to reduce regulatory lag and provide more timely recovery of certain costs.

Given APS' current significant capital expenditure program, the company will require continued, timely regulatory support to maintain credit metrics that are appropriate for its rating. The stable outlooks for APS and Pinnacle assume APS will be reasonably successful in managing its regulatory relationships with an objective of achieving more timely recovery and an opportunity to earn a fair return. The rating also incorporates an expectation that APS will maintain a balanced approach with regards to financing its capital expenditures with a goal of maintaining or improving its current level of financial strength.

The most important drivers of the rating and outlook are as follows:

Predominately Regulated Operations

Pinnacle engages in a modest amount of non-regulated activity; however, it currently derives almost all of its operating cash flow from its regulated electric utility subsidiary APS. Pinnacle's non-regulated operations include a limited amount of energy trading, sales of energy-related products and services and commercial and residential real estate development primarily in Arizona and the southwest. Although residential real estate sales have slowed considerably in 2006, 2007 and in 2008, Pinnacle's joint venture strategy with other developers, combined with its successfully completed asset sales program (implemented 2003-2005) has significantly reduced its exposure to this volatile sector. In 2006 and 2007, as expected, these operations contributed only modestly to consolidated cash flows. Pinnacle anticipates continued weak real estate markets in 2008 and 2009.

Regulatory Environment

Almost all of APS' operations are regulated which is generally viewed as positive for credit quality as regulated cash flows tend to be more stable and predictable than those of unregulated companies. This key factor is tempered somewhat by the historically challenging regulatory environment in Arizona, which Moody's ranks as below average for U.S. regulatory jurisdictions in terms of supportiveness or predictability and stability of regulated cash flows.

APS' operations are regulated by the ACC, an elected commission that has tended to render its decisions after prolonged consideration. Although regulatory lag remains a significant concern, recent decisions with regards to costs for fuel and purchased power and transmission, and certain growth related expenditures should reduce the time to recover some of these items.

General Regulatory Lag

APS' rate case activity is illustrative of an environment where there has tended to be below average assurance of timely recovery of costs and the ability to earn a reasonable return on investment. APS' 2003 rate case was not concluded until April 2005, and the increase received was less than half of the amount requested; the significant delay and relatively modest allowed increase resulted in the need for APS to quickly file another rate case in January 2006.

APS' January 2006 rate case was decided somewhat more quickly with a decision rendered in June 2007 wherein the utility received approximately three quarters of its requested increase; however, the allowed increase was almost entirely related to increased costs for fuel and purchased power. Of the $120 million requested for non-fuel items, only $7 million was approved. As a result, APS filed another general rate case as soon as practicable, based on a test year-ending September 2007. APS subsequently agreed with ACC Staff to re-file its rate increase request based on a test year-ending December 2007. Given the amount of time generally required to decide rate cases in Arizona, Moody's estimates that new rates will not be implemented until the latter part of 2009.

Reduced Regulatory Lag for Certain Items

The ACC's June 2007 decision included a significantly improved mechanism for the recovery of fuel and purchased power costs, incorporating a forward estimate of fuel costs in addition to the continued recovery of past deferrals. Fuel and purchased power costs have been among APS' most volatile operating expenses and Moody's views the ACC's recent approach to this problem as supportive of the utility's credit profile. However, we note that APS fuel recovery factor remains subject to an annual cap, potentially delaying recoveries beyond a one-year true-up period, and subject to a 90/10 sharing mechanism wherein 10% of costs are not able to be recovered.

In June 2008, APS requested an interim base rate increase that would take effect upon expiration in July 2008 of a surcharge being collected under the fuel clause adjustment mechanism. The request could potentially allow base rate cost recovery, subject to refund, prior to the completion of the next general rate case. This could result in a measure of rate stability as there could potentially be no immediate incremental increase to customers, and there would likely ultimately be a smaller base rate increase. Since the ACC and interested parties needed more time to consider this request, a decision is now expected late September to mid October. If implemented new rates could be in place November 1 when lower winter rates go into effect, thereby allowing some degree of rate stability. Moody's notes that the ACC has granted interim increases in the recent past. Moody's views mechanisms designed to reduce the time required to recover a utility's costs, such as the requested interim base rate increase a positive for credit quality.

In its June 2007 order, the ACC requested that APS propose mechanisms that could potentially allow growth to pay for itself, rather than being paid by the current customer base. In February 2008, the ACC approved an amendment to APS' line extension schedule that should provide an almost immediate recovery of the cost of certain growth related capital investment reducing the amount of external financing needed to support these expenditures. Moody's views this revision as positive for credit, virtually eliminating the normal regulatory lag that would otherwise be associated with seeking recovery of these expenditures.

In its 2005 order, the ACC authorized a transmission tracking adjustment (TCA) mechanism designed to allow retail transmission charges to track those authorized by the FERC. The TCA was initially implemented in March 2008, and timely adjusted following an automatic adjustment in FERC transmission rates in June 2008.

Service Territory Growth Slowing

Growth in APS' service territory has slowed significantly below the 4-5% level experienced in 2005 and 2006. In 2007, customer growth was approximately 3%; for the first quarter of 2008 customer growth slowed to 2% and is not expected to return to historical heights over the near-to-medium term. Although, a growing customer base can provide a source of increased revenue, assuming timely recovery of increased growth related investment and increased costs for fuel and purchased power, it also has resulted in a continuing need for capital investment and regulatory relief. The stable outlook assumes APS will continue to take a balanced approach with regards to the funding of its capital expenditures. Moody's also believes a sustained period of slower growth could potentially temper APS need for capital investment which could reduce its financing requirements.

Real Estate Exposure

SunCor Development Company (SunCor), Pinnacle's real estate development subsidiary, is exposed to the volatility inherent in the western real estate markets; however, currently this exposure is relatively modest. In 2005, SunCor completed the last phase of a three year accelerated asset sales program during which time it sent meaningful ($50-100 million per year) dividends to Pinnacle. In 2006 and 2007, SunCor sent Pinnacle a dividend of approximately $10 million. In 2008, only modest, if any, dividends are anticipated from SunCor which has been impacted by the general slowdown in the real estate market and lower residential sales. SunCor's commercial sales remained stronger than residential sales; however, several anticipated 2007 closings, including an office tower at Hayden Ferry Lakeside, were delayed due to conditions in the credit markets. SunCor successfully closed the Haden Ferry Lakeside transaction in June 2008.

SunCor mitigates its exposure to the more volatile aspects of the sector by developing its investments via joint ventures with participating land owners. The company's strategy involves generally making only modest investments until sales agreements are in place. In 2007, SunCor contributed approximately $24 million to Pinnacle's consolidated net income, versus approximately $60 million in 2006, and $55 million in 2005. In 2008, only minimal, if any, earnings are anticipated from SunCor. The subsidiary is not expected to be a significant driver of consolidated earnings or cash flow over the near-to-medium term. SunCor is also not expected to require any additional investment from Pinnacle as the subsidiary is expected to continue to self-fund its investments and has its own non-recourse credit facilities in place.

Financial Metrics

In 2004 and 2005, Pinnacle's key financial metrics reflected the fact that APS had been unable to recover increased costs for fuel and purchased power on a timely basis. For example, the ratio of cash from operations prior to changes in working capital (CFO pre-WC) to adjusted debt (incorporating Moody's standard analytic adjustments) dropped into the mid-teens in 2004 and 2005 then moving to the upper-teens in 2006 and 2007, as fuel recovery improved. These recent ratios are toward the middle of the 13% to 25% range identified in Moody's Rating Methodology for Global Regulated Electric Utilities for Baa rated utility companies within the medium risk category. Given Pinnacle's position toward the mid-to-upper end of the medium business risk category, these metrics are consistent with its Baa3 rating. Cash flow credit metrics are expected to remain in that range over the near-to-medium term, reflecting more timely cost recovery of certain items at APS and assuming capital expenditures are financed in a manner that is also supportive of Pinnacle's current financial strength and flexibility. In general, Moody's would look for Pinnacle to have financial metrics that are somewhat stronger than comparably rated utility parent companies that operate in more supportive regulatory environments and that have a lower level of overall business risk.

Liquidity Profile

As a holding company, Pinnacle's primary source of liquidity is the dividends it receives from its operating subsidiaries, primarily its utility subsidiary, APS. In 2006 and 2007, subsidiary dividends of approximately $180 million covered approximately 77% of Pinnacle's overhead costs, parent level interest expenses of approximately $17 million and common stock dividends of approximately $210 million.

While the dividends Pinnacle receives from SunCor have decreased considerably from approximately $100 million in 2003 to $10 million in 2006 and 2007, the annual dividends it receives from APS have been very stable at $170 million per year. Moody's expects APS' dividends are likely to remain near this level in 2008 and over the medium term.

Pinnacle's $250 million commercial paper program is supported by a $300 million revolving credit facility that expires December 2010. As of March 31, 2008, Pinnacle had approximately $145 million of commercial paper outstanding. APS also has its own $250 million commercial paper program that is supported by two of its own committed lines of credit totaling $900 million, a $400 million line that expires in December 2010 and a $500 million line that expires in September 2011. As of March 31, 2008, APS had approximately $100 million of borrowings under its credit facilities. Overall availability under these credit facilities was $796 million, of which $90 million was back-stopping commercial paper outstanding.

The credit agreements for both Pinnacle and APS have one financial covenant that requires the ratio of debt to total capitalization not to exceed 65%. At March 31, 2008, total debt to total capitalization was approximately 51% for Pinnacle and 47% for APS. None of the credit agreements for Pinnacle or APS require a Material Adverse Change (MAC) representation for revolver borrowings or rating triggers for early repayment though interest costs may increase under various financing agreements if a downgrade occurs. SunCor has its own $150 million secured revolving facility that terminates in December 2008, under which there was approximately $85 million outstanding as of December 2007. SunCor also had some, primarily two-year, construction loans aggregating under $150 million due primarily in 2008 and 2009. The SunCor loans and revolver are secured by specific interests in land, commercial properties, land contracts and/or homes under construction and are non-recourse to Pinnacle.

On a consolidated basis, capital expenditures in 2008 are expected to be approximately $1 billion, with approximately $50 million at SunCor. APS is expected to finance its capital expenditures from internal and external sources, including equity infusions from Pinnacle. SunCor is expected to finance its capital expenditures via a combination of its own operating cash flow and external financing.

Long-term debt at the Pinnacle parent level is limited to a $175 million of 5.91% senior notes due February 2011.

Pinnacle's Prime-3 rating for its short-term obligations assumes that the company will manage the amount of commercial paper and other near term obligations outstanding within the limits of its readily available sources of cash, including its committed bank credit facilities.

Rating Outlook

The stable outlook for Pinnacle reflects the nature of APS' predominately regulated cash flows and Moody's view that its improved cash flow financial metrics are likely to be sustainable. The outlook assumes APS' will be reasonably successful in managing its regulatory relationships and that capital expenditures will be financed in a balanced manner with a goal of maintaining or improving Pinnacle's current position of financial strength.

What Could Change the Rating - Up

Pinnacle' rating is not likely to be revised upward in the near-to-medium term. Longer term, if there to be an increase in supportive regulatory treatment at APS resulting in material, timely rate increases, or if there were to be material reductions in costs or leverage such that Moody's could anticipate key financial ratios improving significantly from their current levels, if for example, a ratio of CFO pre -WC / debt could be maintained in the low twenty percent range.

What Could Change the Rating - Down

A downgrade could result if Palo Verde experiences an extended outage and APS is unable to recover, in a timely manner, higher maintenance and purchased power costs, or if APS' regulatory lag for capital spending becomes more pronounced. A downgrade could result if Moody's expects a sustained weakening of financial metrics, if for example, the ratio of CFO pre -WC / debt would remain below the mid-teens for an extended period. A downgrade could also result if there were to be an increase in Pinnacle's consolidated business risk profile; if for example, it were to materially increase its investment in, or its commitments to its more volatile, non-regulated operations, including SunCor.

Rating Factors

Pinnacle West Capital Corporation

609400

Select Key Ratios for Global Regulated Electric Utilities

Rating	Aa	Aa	A	A	Baa	Baa	Ba	Ba
Level of Business Risk	**Medium**	**Low**	**Medium**	**Low**	**Medium**	**Low**	**Medium**	**Low**
CFO pre-W/C to Interest (x) [1]	>6	>5	3.5-6.0	3.0-5.7	2.7-5.0	2-4.0	<2.5	<2
CFO pre-W/C to Debt (%) [1]	>30	>22	22-30	12-22	13-25	5-13	<13	<5
CFO pre-W/C - Dividends to Debt (%) [1]	>25	>20	13-25	9-20	8-20	3-10	<10	<3
Total Debt to Book Capitalization (%)	<40	<50	40-60	50-70	50-70	60-75	>60	>70

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

Moody's Investors Service

Global Credit Research
Credit Opinion
28 JUL 2008

Credit Opinion: Arizona Public Service Company

Arizona Public Service Company

Phoenix, Arizona, United States

Ratings

Category	**Moody's Rating**
Outlook	Stable
Issuer Rating	Baa2
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Subordinate Shelf	(P)Baa3
Commercial Paper	P-2
Parent: Pinnacle West Capital Corporation	
Outlook	Stable
Issuer Rating	Baa3
Sr Unsec Bank Credit Facility	Baa3
Senior Unsecured Shelf	(P)Baa3
Subordinate Shelf	(P)Ba1
Preferred Shelf	(P)Ba2
Commercial Paper	P-3

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Key Indicators

Arizona Public Service Company

ACTUALS	**1Q08 LTM**	**2007**	**2006**	**2005**
(CFO Pre-W/C + Interest) / Interest Expense [1][2]	**4.4x**	**4.2x**	**4.4x**	**3.6x**
(CFO Pre-W/C) / Debt [2]	**19.6%**	**18.3%**	**19.0%**	**14.5%**
(CFO Pre-W/C - Dividends) / Debt [2]	**14.1%**	**14.0%**	**14.5%**	**9.7%**
(CFO Pre-W/C - Dividends) / Capex [2]	**56.0%**	**58.7%**	**79.0%**	**53.1%**
Debt / Book Capitalization	**45.9%**	**45.9%**	**46.0%**	**47.5%**
EBITA Margin	**21.7%**	**22.6%**	**23.9%**	**20.9%**

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items [2] Changes in risk management and trading assets and liabilities are excluded from CFO Pre-W/C

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Corporate Profile

Arizona Public Service (APS: Baa2 senior unsecured, stable) is a vertically integrated electric utility that provides electric service to most of the state of Arizona with the major exceptions of about one-half of the Phoenix metropolitan area and the Tucson metropolitan area. APS is the primary subsidiary of Pinnacle West Capital Corporation (Pinnacle: Baa3 senior unsecured, stable), a holding company that through its other subsidiaries sells energy related products and services and develops residential and commercial real estate.

Recent Events

On July 25, 2008 Moody's revised the outlooks for APS and Pinnacle to stable from negative. The revision in outlook was a result of the companies' stable financial performance and also reflects our opinion of APS' improved prospects for more timely recovery of certain costs than had historically been the case. Our view is based on recent regulatory decisions involving recovery mechanisms for the cost of fuel and purchased power and transmission as well as recovery mechanisms for certain growth related costs. The outlook revision also recognized APS' demonstrated intent to attempt to minimize regulatory lag by filing for additional rate relief as soon as practicable.

Regulatory Activity

Approval of Line Extension Fees

In February 2008 the Arizona Corporation Commission (ACC) approved an amendment to APS' line extension schedule which eliminated certain free footage allowances and permitted APS to collect, on a current basis, costs relating to line extensions, which are estimated to be approximately $3,500 - $5,000 per new meter set (pre-tax). Moody's views the incremental (after-tax) cash flow resulting from these fees as recurring, and we have adjusted our credit metrics to reflect them as operating cash flows.

General Rate Case Filing

In June 2008, APS filed for a $278.2 million net rate increase (approximately 8.5% from existing customers) comprised of a $264.3 million non-fuel related increase and a $13.9 million net fuel-related increase. APS has proposed to collect up to $53 million of the increase specifically from new customers. The fuel increase request is net of approximately $170 million currently being collected in APS rates through its power supply adjustor (PSA) mechanism. APS' June filing is based on a test year ended December 2007. The request has been accepted by ACC Staff. A procedural schedule has been proposed with hearings in April 2009 and a decision expected in the latter part of 2009.

Request for Interim Increase

Also in June 2008, APS filed a request for an interim base rate increase of $.003987 per kWh to become effective upon the expiration of the $.003987 per kWh power supply adjustor surcharge currently in APS' rates. APS estimates the current surcharge will remain in effect through July. A procedural schedule has been set for this request, with hearings scheduled for September 2008 with a decision anticipated shortly thereafter.

Palo Verde

In February 2007, Nuclear Regulatory Commission (NRC) placed Palo Verde Unit 3 (PVU3), into the "multiple/repetitive degraded cornerstone" column of the NRC's action matrix, which has resulted in an enhanced inspection regimen and some increased operating costs for APS as it seeks to improve its processes at all three Palo Verde units. In February 2008, the NRC issued its revised confirmatory action letter, and as required, on March 31, 2008, APS submitted its revised improvement plan. The NRC will continue to provide increased oversight at Palo Verde until the facility has demonstrated sustained performance improvement. APS anticipates that this process will continue into 2009.

While operating performance at Palo Verde has improved, capacity factors continue to be impacted by planned outages (including a steam generator replacement in 2007) that have been extended by additional inspections. In 2007, the plant's average capacity factor was 79.0% versus 70.7% in 2006 and 77.4% in 2005. For the first quarter of 2008, the nuclear capacity factor was 93%.

Rating Rationale

The Baa2 rating for the senior unsecured obligations of APS reflects the stability of its regulated cash flows, the economic strength of its service territory, its regulatory environment, cash flow credit metrics that are appropriate

for the rating, and its position as a subsidiary of Pinnacle. The rating and outlook consider the traditionally challenging regulatory environment in Arizona, but also contemplates recent ACC decisions and regulatory activities that appear intended to reduce regulatory lag and provide more timely recovery of certain costs.

Given APS' current significant capital expenditure program, the company will require continued, timely regulatory support to maintain credit metrics that are appropriate for its rating. The stable outlook assumes APS will be reasonably successful in managing its regulatory relationships with an objective of achieving more timely recovery and an opportunity to earn a fair return. The rating also incorporates an expectation that APS will maintain a balanced approach with regards to financing its capital expenditures with a goal of maintaining or improving its current level of financial strength.

The most important drivers of the rating and outlook are as follows:

Regulatory Environment

Almost all of APS' operations are regulated which is generally viewed as positive for credit quality as regulated cash flows tend to be more stable and predictable than those of unregulated companies. This key factor is tempered somewhat by the historically challenging regulatory environment in Arizona, which Moody's ranks as below average for U.S. regulatory jurisdictions in terms of supportiveness or predictability and stability of regulated cash flows.

APS' operations are regulated by the ACC, an elected commission that has tended to render its decisions after prolonged consideration. Although regulatory lag remains a significant concern, recent decisions with regards to costs for fuel and purchased power and transmission, and certain growth related expenditures should reduce the time to recover some of these items.

General Regulatory Lag

APS' rate case activity is illustrative of an environment where there has tended to be below average assurance of timely recovery of costs and the ability to earn a reasonable return on investment. APS' 2003 rate case was not concluded until April 2005, and the increase received was less than half of the amount requested; the significant delay and relatively modest allowed increase resulted in the need for APS to quickly file another rate case in January 2006.

APS' January 2006 rate case was decided somewhat more quickly with a decision rendered in June 2007 wherein the utility received approximately three quarters of its requested increase; however, the allowed increase was almost entirely related to increased costs for fuel and purchased power. Of the $120 million requested for non-fuel items, only $7 million was approved. As a result, APS filed another general rate case as soon as practicable, based on a test year-ending September 2007. APS subsequently agreed with ACC Staff to re-file its rate increase request based on a test year-ending December 2007. Given the amount of time generally required to decide rate cases in Arizona, Moody's estimates that new rates will not be implemented until the latter part of 2009.

Reduced Regulatory Lag for Certain Items

The ACC's June 2007 decision included a significantly improved mechanism for the recovery of fuel and purchased power costs, incorporating a forward estimate of fuel costs in addition to the continued recovery of past deferrals. Fuel and purchased power costs have been among APS' most volatile operating expenses and Moody's views the ACC's recent approach to this problem as supportive of the utility's credit profile. However, we note that APS fuel recovery factor remains subject to an annual cap, potentially delaying recoveries beyond a one-year true-up period, and subject to a 90/10 sharing mechanism wherein 10% of costs are not able to be recovered.

In June 2008, APS requested an interim base rate increase that would take effect upon expiration in July 2008 of a surcharge being collected under the fuel clause adjustment mechanism. The request could potentially allow base rate cost recovery, subject to refund, prior to the completion of the next general rate case. This could result in a measure of rate stability as there could potentially be no immediate incremental increase to customers, and there would likely ultimately be a smaller base rate increase. Since the ACC and interested parties needed more time to consider this request, a decision is now expected late September to mid October. If implemented new rates could be in place November 1 when lower winter rates go into effect, thereby allowing some degree of rate stability. Moody's notes that the ACC has granted interim increases in the recent past. Moody's views mechanisms designed to reduce the time required to recover a utility's costs, such as the requested interim base rate increase a positive for credit quality.

In its June 2007 order, the ACC requested that APS propose mechanisms that could potentially allow growth to

pay for itself, rather than being paid by the current customer base. In February 2008, the ACC approved an amendment to APS' line extension schedule that should provide an almost immediate recovery of the cost of certain growth related capital investment reducing the amount of external financing needed to support these expenditures. Moody's views this revision as positive for credit, virtually eliminating the normal regulatory lag that would otherwise be associated with seeking recovery of these expenditures.

In its 2005 order, the ACC authorized a transmission tracking adjustment (TCA) mechanism designed to allow retail transmission charges to track those authorized by the FERC. The TCA was initially implemented in March 2008, and timely adjusted following an automatic adjustment in FERC transmission rates in June 2008.

Service Territory Growth Slowing

Growth in APS' service territory has slowed significantly below the 4-5% level experienced in 2005 and 2006. In 2007, customer growth was approximately 3%; for the first quarter of 2008 customer growth slowed to 2% and is not expected to return to historical heights over the near-to-medium term. Although, a growing customer base can provide a source of increased revenue, assuming timely recovery of increased growth related investment and increased costs for fuel and purchased power, it also has resulted in a continuing need for capital investment and regulatory relief. The stable outlook assumes APS will continue to take a balanced approach with regards to the funding of its capital expenditures. Moody's also believes a sustained period of slower growth could potentially temper APS need for capital investment which could reduce its financing requirements.

Financial Metrics

In 2004 and 2005, APS' key financial metrics reflected the fact that it had been unable to recover fully increased costs for fuel, purchased power and capital spending on a timely basis. For example, the ratio of cash from operations prior to changes in current assets and liabilities (CFO pre-WC) / debt (incorporating Moody's standard analytic adjustments) dropped into the mid-teens. Financial metrics improved in 2006 and 2007 with CFO pre - WC / debt moving to the upper-teens as fuel recovery improved. These metrics are now toward the middle-to-upper end of the 13% to 25% range identified in Moody's Rating Methodology for Global Electric Utilities for Baa rated entities on a stand-alone basis within the medium risk category. Cash flow credit metrics are expected to remain in that range over the near-to-medium term reflecting more timely cost recovery of certain items and assuming capital expenditures are financed in a manner that is also supportive of APS current financial strength and flexibility. In general, Moody's would look for APS to have financial metrics that are somewhat stronger than comparably rated utility operating companies that operate in regulatory environments that have historically been more supportive of credit quality.

Subsidiary of Pinnacle West

Pinnacle, APS' parent company, conducts a modest amount of non-regulated activities including power marketing and trading, sales of energy related products and services, and residential and commercial real estate development through subsidiaries including SunCor Development Company (real estate). However, for the past several years almost all of Pinnacle's cash from operations has been generated by APS. Over the near-to-medium term, Pinnacle's non-regulated businesses, are not expected to meaningfully contribute to, or detract from, consolidated cash flows. Although residential real estate sales slowed considerably in 2006, 2007 and continuing into 2008, Pinnacle's joint venture strategy with other developers, combined with its successfully completed asset sales program (implemented 2003-2005) has significantly reduced its exposure to this volatile sector. The parent company also maintains a modest amount of leverage with holding company debt at less than 10% of consolidated debt.

Liquidity Profile

APS' Prime-2 short-term rating for commercial paper reflects the relatively stable and predictable cash flow provided by its regulated electric utility operations.

For the year ended December 2007, APS' cash flow from operations of approximately $765 million covered approximately 72% of its outlays, including capital expenditures of approximately $900 million and dividends to Pinnacle of $170 million. The shortfall was funded via a combination of internal and external sources of cash including $218 million of short term debt proceeds, approximately $40 million of equity contributions from Pinnacle and cash on hand.

For the next several years, APS' capital expenditures are expected to be in the range of $1.0 billion per year, primarily to expand APS' transmission and distribution network to meet growing customer needs, but also to upgrade its existing utility properties and for other environmental purposes. Funding for these increased capital

expenditures is expected to be provided via a combination of internal and external sources of cash, including operating cash flow, equity contributions from Pinnacle and long and short term debt financing.

Over the last several years, APS has paid dividends to Pinnacle of $170 million per year. Moody's expects APS' dividends are likely to remain near this level in 2008 and over the medium term.

APS' pattern of cash flow is seasonal as the peak of electric demand occurs during the summer months due to high air conditioning load that exists in its service territory. As a result, the bulk of its commercial paper borrowings typically occur in the second and third quarters of each year. As of March 31, 2008, APS had $90 million of commercial paper and $100 of short-term debt outstanding under its revolving credit facility.

APS has historically maintained a very modest level of cash on its balance sheet; as of March 31, 2008, APS had reported cash and cash equivalents of approximately $8 million.

APS' commercial paper program is sized at $250 million and is currently supported by two committed lines of credit totaling $900 million, a $400 million line that expires in December 2010 and a $500 million line that expires in September 2011. As of March 31, 2008, APS had approximately $100 million of borrowings under its credit facilities. Overall availability under these credit facilities was $796 million, of which $90 million was back-stopping commercial paper outstanding. Both credit agreements have one financial covenant that requires the ratio of debt to total capitalization not to exceed 65%. As of March 31, 2008, APS' debt to total capitalization ratio, calculated in accordance with the credit documents, was approximately 47%. The credit agreements do not require a Material Adverse Change (MAC) representation for revolver borrowings. No rating triggers exist in any APS credit facilities though interest costs may increase under various financing agreements if a downgrade occurs. APS nearest long term debt maturity is $400 million of unsecured notes due in 2011. In 2010, APS must replace letters of credit supporting approximately $200 million of variable rate pollution control bonds.

APS' Prime-2 rating for its short term obligations assumes that the company will manage the amount of commercial paper and other near term obligations outstanding within the limits of its readily available sources of cash, including its committed bank credit facilities.

Rating Outlook

The stable outlook reflects the nature of APS' predominately regulated cash flows and Moody's view that its improved cash flow financial metrics are likely to be sustainable. The outlook assumes APS' will be reasonably successful in managing its regulatory relationships and that capital expenditures will be financed in a balanced manner with a goal of maintaining or improving APS current position of financial strength.

What Could Change the Rating - Up

APS' rating is not likely to be revised upward in the near-to-medium term. Longer term, if there is an increase in supportive regulatory treatment resulting in material, timely rate increases, or if there are material reductions in costs or leverage such that Moody's could anticipate key financial ratios improving significantly from their current levels, if for example, a ratio of CFO pre -WC / debt could be maintained in the mid twenty percent range.

What Could Change the Rating - Down

A downgrade could result if Palo Verde experiences an extended outage and APS is unable to recover, in a timely manner, higher maintenance and purchased power costs, or if APS' regulatory lag for capital spending becomes more pronounced. A downgrade could result if Moody's expects a sustained weakening of financial metrics, if for example, the ratio of CFO pre -WC / debt would remain in the mid-teens for an extended period.

Rating Factors

Arizona Public Service Company

62000

Select Key Ratios for Global Regulated Electric Utilities

Rating	Aa	Aa	A	A	Baa	Baa	Ba	Ba
Level of Business Risk	Medium	Low	Medium	Low	Medium	Low	Medium	Low

CFO pre-W/C to Interest (x) [1]	>6	>5	3.5-6.0	3.0-5.7	2.7-5.0	2-4.0	<2.5	<2
CFO pre-W/C to Debt (%) [1]	>30	>22	22-30	12-22	13-25	5-13	<13	<5
CFO pre-W/C - Dividends to Debt (%) [1]	>25	>20	13-25	9-20	8-20	3-10	<10	<3
Total Debt to Book Capitalization (%)	<40	<50	40-60	50-70	50-70	60-75	>60	>70

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

Moody's Investors Service

Global Credit Research
Rating Action
25 JUL 2008

Rating Action: Arizona Public Service Company

Moody's revises outlook of Pinnacle West and Arizona Public Service to stable

Approximately $3 billion of debt securities affected

New York, July 25, 2008 -- Moody's Investors Service changed the rating outlooks of Pinnacle West Capital Corporation (Pinnacle, Baa3 senior unsecured) and its subsidiaries, Arizona Public Service Company (APS, Baa2 senior unsecured) and PVNGS II Funding Corp. Inc. (PVNGS II: Baa2, senior secured lease obligation bonds) to stable from negative.

The stable outlook considers the companies' improving regulatory environment and operating performance with financial results that are expected to remain consistently within the range expected for integrated utilities rated Baa. APS has begun to receive more supportive regulatory decisions, including "new connection" fees allowing faster recovery for new hookups plus a transmission cost adjustor and power supply adjustor which has limited APS' exposure to fuel and purchased power fluctuations. In addition, performance at the Palo Verde nuclear power plant has improved and APS is making progress in identifying and improving the safety and communication issues at the plant.

As a result of some improved timing on cost recoveries, Moody's now expects APS and Pinnacle's cash flow credit metrics to remain at levels comparable to those achieved in 2006 and 2007. This would place the utility and parent in the mid-to-upper range of ratios for electric utilities with medium business risk according to Moody's rating methodology for global regulated electric utilities. For the twelve months ended March 31, 2008, APS' cash from operations pre-working capital (CFO pre-WC) interest coverage was 4.4x and CFO pre-WC to debt was 19.6% which was comparable to year-end 2006 and slightly above the 18.3% and 4.2x metrics registered in 2007. Pinnacle's CFO pre-WC interest coverage of 4.0x and CFO pre-WC to Debt of 17.5% for the twelve months ended March 31, 2008 were modestly below 2006 levels but comparable to 2007 levels where they still remain within the middle of the range for Baa rated electric utilities. We expect these metrics to remain roughly within this range going forward.

The stable outlook also is predicated on an expectation for continued improvement at Palo Verde such that current heightened regulatory scrutiny is reduced to normal levels over the medium term and that more balanced regulatory relief continues especially given that APS has several rate filings currently pending. We also expect Pinnacle to continue to finance APS' capital expenditures in a manner consistent with its investment-grade rating.

Pinnacle West Capital Corporation, headquartered in Phoenix, Arizona, provides electric service to a substantial portion of the state of Arizona, sells energy-related products and services, and develops residential, commercial and industrial real estate. Pinnacle conducts its business through its subsidiaries. Wholly-owned Arizona Public Service Company is its principal subsidiary.

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Moody's Investors Service

Global Credit Research
Credit Opinion
17 DEC 2007

Credit Opinion: Pinnacle West Capital Corporation

Pinnacle West Capital Corporation

United States

Ratings

Category	Moody's Rating
Outlook	Negative
Issuer Rating	Baa3
Sr Unsec Bank Credit Facility	Baa3
Senior Unsecured Shelf	(P)Baa3
Subordinate Shelf	(P)Ba1
Preferred Shelf	(P)Ba2
Commercial Paper	P-3
Arizona Public Service Company	
Outlook	Negative
Issuer Rating	Baa2
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Subordinate Shelf	(P)Baa3
Commercial Paper	P-2

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Key Indicators

Pinnacle West Capital Corporation

ACTUALS	3Q07 LTM	2006	2005	2004
(CFO Pre-W/C + Interest) / Interest Expense [1][2][3]	4.6x	4.2x	3.7x	3.9x
(CFO Pre-W/C) / Debt [2][3]	20.5%	18.9%	16.4%	16.0%
(CFO Pre-W/C - Dividends) / Debt [2][3]	15.9%	14.1%	11.8%	12.1%
(CFO Pre-W/C - Dividends) / Capex [2][3]	74.0%	75.2%	69.6%	88.5%
Debt / Book Capitalization	48.2%	47.4%	48.0%	51.7%
EBITA Margin	17.4%	18.4%	18.9%	22.2%

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items [2] Excludes the impact of a tax reversal in 2004. [3] Changes in risk management and trading assets and liabilities are excluded from CFO Pre-W/C

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Company Profile

Pinnacle West Capital Corporation (Pinnacle: Baa3 senior unsecured, negative outlook) is a holding company whose principal subsidiary, Arizona Public Service Corporation (APS: Baa2 senior unsecured, negative outlook), is a vertically integrated electric utility that provides electric service to most of the state of Arizona with the major exceptions of about one-half of the Phoenix metropolitan area and the Tucson metropolitan area. Pinnacle's other subsidiaries are engaged in the sale of energy related products and services and the development of residential and commercial real estate.

Rating Rationale

The Baa3 rating for Pinnacle's senior unsecured obligations is driven primarily by the stable cash flows that are provided almost entirely by APS, its regulated electric utility subsidiary, the economic strength of APS' service territory, the regulatory environment in Arizona, and Pinnacle's modest exposure to a currently weak real estate market. The negative outlook is primarily a reflection of APS' continued need for rate increases in a regulatory arena that has historically been challenging. Given APS significant capital expenditure program, the company will require continued, timely regulatory support to maintain credit metrics that are appropriate for its rating.

The most important drivers of the rating and outlook are as follows:

Predominately Regulated Operations

Pinnacle engages in a modest amount of non-regulated activity; however, it currently derives almost all of its operating cash flow from its regulated electric utility subsidiary APS. Pinnacle's non-regulated operations include a limited amount of energy trading, sales of energy-related products and services and commercial and residential real estate development primarily in Arizona and the southwest. Although residential real estate sales have slowed considerably in 2006 and 2007, Pinnacle's joint venture strategy, combined with its successfully completed asset sales program (implemented 2003-2005) has reduced its exposure to this volatile sector. In 2006 and 2007, as expected, these operations contributed only modestly to consolidated cash flows and Pinnacle anticipates continued weak residential real estate markets in 2008. Pinnacle's high degree of regulated activity is generally viewed as positive for credit quality; however this key factor is tempered somewhat by the historically challenging regulatory environment in Arizona, which Moody's ranks as below average for U.S. regulatory jurisdictions in terms of supportiveness.

Challenging Regulatory Environment

APS' operations are regulated by the Arizona Corporation Commission (ACC), an elected commission that has tended to render its decisions after prolonged consideration. APS' rate case activity is illustrative of an environment where there has tended to be below average assurance of timely recovery of costs and the ability to earn a reasonable return on investment. APS' 2003 rate case was not concluded until April 2005, and the increase received was less than half of the amount requested; the significant delay and relatively modest allowed increase resulted in the need for APS to quickly file another rate case in January 2006.

APS' January 2006 rate case was decided somewhat quicker with a decision rendered in June 2007 wherein the utility received approximately three quarters of its requested increase; however, the allowed increase was almost entirely related to increased costs for fuel and purchased power. The 2007 decision included a significantly improved mechanism for the recovery of fuel and purchased power costs, incorporating a forward estimate of fuel costs in addition to the continued recovery of past deferrals. Fuel and purchased power costs have been among APS' most volatile operating expenses and Moody's views the ACC's recent approach to this problem as supportive of the utility's credit profile. Nevertheless, as part of the June decision, the ACC approved a severely limited percentage of APS requested revenue increase for non-fuel items, including capital investment ($7 million versus a request of approximately $120 million). Given APS' growth rate, and its associated need for increased capital spending, this remains an area of concern for credit quality. Moody's believes APS will need to seek additional rate relief in the near-to-medium term.

In its June order, the ACC requested that APS propose mechanisms that could potentially allow growth to pay for itself, rather than being paid by the current customer base. The ACC is now considering an APS proposed amendment to its line extension schedule, or "hook-up-fees", that could potentially provide a relatively timely source of funding for growth related capital investment and potentially reduce the size of, or extend the time before, APS' next general rate case.

Growing Service Territory

Pinnacle's rating also recognizes the on-going strong growth in APS' service territory. In 2007, customer growth has been approximately 3%. Although somewhat below the 4-5% pace experienced in 2005 and 2006, growth is still significantly higher than the national average and is expected to remain around this level over the medium term. APS' increasing customer base has resulted in a continuing need for capital investment, but it also provides a source of revenue growth outside of base rate increases which could be expected to improve financial metrics assuming there is relatively timely recovery of increased growth related investment and fuel and purchased power costs.

APS' currently proposed amendment to its line extension schedule, if accepted, could shift some of the costs of growth to those new customers directly responsible for the increased costs, reducing the negative impacts of continued growth on APS and Pinnacle going forward.

Real Estate Exposure

SunCor Development Company (SunCor), Pinnacle's real estate development subsidiary is exposed to the volatility inherent in the western real estate markets; however, currently this exposure is relatively modest. In 2005, SunCor completed the last phase of a three year accelerated asset sales program during which time it sent meaningful ($50-100 million per year) dividends to Pinnacle. In 2006, as anticipated, SunCor sent Pinnacle a dividend of approximately $10 million. In 2007, similar to 2006, only a modest dividend is anticipated. SunCor has been impacted by the general slowdown in the real estate market and has experienced lower residential sales. SunCor's commercial sales remain stronger than residential sales; however, several recently anticipated 2007 closings have been delayed due to conditions in the credit markets.

SunCor mitigates its exposure to the more volatile aspects of the sector by developing its investments via joint ventures with participating land owners. The company's strategy involves generally making only modest investments until sales agreements are in place. In Pinnacle's 2007 budget, SunCor was expected to contribute approximately $30 million to net income; SunCor earnings are now expected to be approximately $20 million and a modest dividend is still anticipated. The subsidiary is not expected to be a significant driver of consolidated earnings or cash flow over the near-to-medium term. SunCor is also not expected to require any additional investment from Pinnacle as the subsidiary is expected to continue to self-fund its investments and has its own non-recourse credit facilities in place.

Financial Metrics

Pinnacle's key financial metrics reflect the fact that APS has been unable to recover increased costs for fuel and purchased power on a timely basis. For example, the ratio of cash from operations prior to changes in working capital (CFO pre-WC) to adjusted debt (incorporating Moody's standard analytic adjustments) dropped into the mid-teens in 2004 and 2005 then moving to the upper-teens in 2006 and for the twelve months ending September 2007, as fuel recovery improved. These recent ratios are toward the middle of the 13% to 25% range identified in Moody's Rating Methodology for Global Regulated Electric Utilities for Baa rated utility companies within the medium risk category. Given Pinnacle's position toward the mid-to-upper end of the medium business risk category, these metrics are consistent with its Baa3 rating. Based on APS' significant planned capital expenditure program, Moody's believes that in order for Pinnacle's credit metrics to remain near their current levels, APS will require additional supportive regulatory treatment and a financing strategy that is consistent with maintaining its financial strength and flexibility. The negative outlook reflects Moody's concern with the potential for metrics to return to the ranges demonstrated in 2004 and 2005 over the next 12 - 18 months which could warrant a downward revision in the ratings. In general, Moody's would look for Pinnacle to have financial metrics that are somewhat stronger than comparably rated utility parent companies that operate in more supportive regulatory environments and that have a lower level of overall business risk.

Liquidity

As a holding company, Pinnacle's primary source of liquidity is the dividends it receives from its operating subsidiaries, primarily its utility subsidiary APS. In 2006 and 2007, subsidiary dividends of approximately $180 million covered approximately 80% of Pinnacle's overhead costs, parent level interest expenses of approximately $10 million and common stock dividends of approximately $210 million.

While the dividends Pinnacle receives from SunCor have decreased considerably from approximately $100 million in 2003 to $10 million in 2006, the annual dividends it receives from APS have been very stable at $170 million per year. Beyond 2007, Moody's anticipates a modest increase in dividends up-streamed from APS but no significant contributions from Pinnacle's unregulated businesses.

Pinnacle's $250 million commercial paper program is supported by a $300 million revolving credit facility that expires December 2010. As of September 30, 2007, Pinnacle had $105 million borrowings outstanding under this credit facility. APS also has its own $250 million commercial paper program that is supported by two of its own committed lines of credit totaling $900 million, a $400 million line that expires in December 2010 and a $500 million line that expires in September 2011. As of September 30, 2007 APS overall availability under these credit facilities was $750 million.

The credit agreements for both Pinnacle and APS have one financial covenant that requires the ratio of debt to total capitalization not to exceed 65%. At September 30, 2007, total debt to total capitalization was approximately 49% for Pinnacle and 46% for APS. None of the credit agreements for Pinnacle or APS require a Material Adverse Change (MAC) representation for revolver borrowings or rating triggers for early repayment though interest costs may increase under various financing agreements if a downgrade occurs. SunCor has its own $150 million secured revolving facility that terminates in December 2008, as well as some, primarily two-year, construction loans aggregating under $200 million due primarily in 2008 and 2009. The SunCor loans and revolver are secured by specific interest in land, commercial properties, land contracts and/or homes under construction and are non-recourse to Pinnacle.

On a consolidated basis, capital expenditures in 2008 are expected to be approximately $1,070 million, including approximately $950 million at APS and $100 million at SunCor. APS is expected to finance its capital expenditures from internal and external sources, including equity infusions from Pinnacle. SunCor is expected to finance its capital expenditures via a combination of its own operating cash flow and external financing.

Long-term debt at the Pinnacle parent level is limited to a $175 million of 5.91% senior notes due February 2011.

Pinnacle's Prime-3 rating for its short-term obligations assumes that the company will manage the amount of commercial paper and other near term obligations outstanding within the limits of its readily available sources of cash, including its committed bank credit facilities.

Recent Events

Palo Verde

The operational performance of the 3,800 MW APS operated Palo Verde nuclear generating facility (which provides approximately 1,100 MWs to APS), improved significantly in 2007. As of September 30, 2007, Palo Verde's year-to-date capacity factor was 86%, versus 71% for 2006 and 77% for 2005.

However, as a result of a February 2007 "white" finding by the Nuclear Regulatory Commission (NRC) involving emergency diesel generators at Palo Verde Unit 3 (PVU3), in combination with a "yellow" finding in 2004 relating to its safety injection systems, PVU3 was placed into the "multiple/repetitive degraded cornerstone" column of the NRC's action matrix, which has resulted in an enhanced inspection regimen and some increased operating costs for APS as it seeks to improve its processes at all three Palo Verde units. In June 2007, the NRC issued an initial confirmatory action letter confirming APS' commitments regarding specific actions APS will take to improve Palo Verde's performance, and from October through November a team of NRC inspectors performed on-site in-depth inspections. APS expects to be informed of the NRC's findings in late December 2007 or early January 2008, and based on the NRC's findings, will make additional modifications to its improvement plan in 2008.

Rating Outlook

Pinnacle's negative outlook reflects Moody's view that given APS' significant capital expenditure plans, absent any relatively near term supportive regulatory intervention or cost or leverage reductions, credit metrics and financial flexibility are likely to weaken over the near-to-medium term.

What Could Change the Rating - Up

In light of the negative outlook, Pinnacle's rating is not likely to be revised upward in the near-to-medium term. The rating outlook could be stabilized if regulatory treatment is supportive, or there were to be material reductions in costs or leverage such that Moody's could anticipate key consolidated financial metrics remaining near the levels demonstrated in 2007, if for example, a ratio of CFO pre-WC to adjusted debt could be maintained in the high teens.

What Could Change the Rating - Down

A downgrade could result if Palo Verde experiences an extended outage and APS is unable to recover, in a timely manner, higher maintenance and purchased power costs, or if APS' regulatory lag for capital spending does not improve, such that Moody's could expect a weakening of financial metrics, if for example, the ratio of CFO pre-WC to adjusted debt would remain in the mid-teens for an extended period. A downgrade could also result if there were to be an increase in Pinnacle's consolidated business risk profile; if for example, it were to materially increase its investment in, or its commitments to its more volatile, non-regulated operations, including SunCor.

Rating Factors

Pinnacle West Capital Corporation

609400

Select Key Ratios for Global Regulated Electric Utilities

Rating	**Aa**	**Aa**	**A**	**A**	**Baa**	**Baa**	**Ba**	**Ba**
Level of Business Risk	**Medium**	**Low**	**Medium**	**Low**	**Medium**	**Low**	**Medium**	**Low**
CFO pre-W/C to Interest (x) [1]	>6	>5	3.5-6.0	3.0-5.7	2.7-5.0	2-4.0	<2.5	<2
CFO pre-W/C to Debt (%) [1]	>30	>22	22-30	12-22	13-25	5-13	<13	<5
CFO pre-W/C - Dividends to Debt (%) [1]	>25	>20	13-25	9-20	8-20	3-10	<10	<3
Total Debt to Book Capitalization (%)	<40	<50	40-60	50-70	50-70	60-75	>60	>70

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

Moody's Investors Service

Global Credit Research
Credit Opinion
17 DEC 2007

Credit Opinion: Arizona Public Service Company

Arizona Public Service Company

Phoenix, Arizona, United States

Ratings

Category	**Moody's Rating**
Outlook	Negative
Issuer Rating	Baa2
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Subordinate Shelf	(P)Baa3
Commercial Paper	P-2
Parent: Pinnacle West Capital Corporation	
Outlook	Negative
Issuer Rating	Baa3
Sr Unsec Bank Credit Facility	Baa3
Senior Unsecured Shelf	(P)Baa3
Subordinate Shelf	(P)Ba1
Preferred Shelf	(P)Ba2
Commercial Paper	P-3

Contacts

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William L. Hess/New York	212.553.3837

Key Indicators

Arizona Public Service Company

ACTUALS	**3Q07 LTM**	**2006**	**2005**	**2004**
(CFO Pre-W/C + Interest) / Interest Expense [1][2][3]	**4.9x**	**4.4x**	**3.6x**	**3.8x**
(CFO Pre-W/C) / Debt [2][3]	**21.5%**	**19.0%**	**14.5%**	**15.8%**
(CFO Pre-W/C - Dividends) / Debt [2][3]	**17.1%**	**14.5%**	**9.7%**	**11.1%**
(CFO Pre-W/C - Dividends) / Capex [2][3]	**74.2%**	**79.0%**	**53.1%**	**71.9%**
Debt / Book Capitalization	**45.8%**	**46.0%**	**47.5%**	**54.0%**
EBITA Margin	**23.9%**	**23.9%**	**20.9%**	**24.5%**

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items [2] Excludes the impact of a tax reversal in 2004. [3] Changes in risk management and trading assets and liabilities are excluded from CFO Pre-W/C

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Company Profile

Arizona Public Service (APS: Baa2 senior unsecured, negative outlook) is a vertically integrated electric utility that provides electric service to most of the state of Arizona with the major exceptions of about one-half of the Phoenix metropolitan area and the Tucson metropolitan area. APS is the primary subsidiary of Pinnacle West Capital Corporation (Pinnacle: Baa3 senior unsecured, negative outlook), a holding company that through its other subsidiaries sells energy related products and services and develops residential and commercial real estate.

Rating Rationale

The Baa2 rating for the senior unsecured obligations of APS reflects the stability of its regulated cash flows, the economic strength of its service territory, its regulatory environment, and its position as the primary wholly owned subsidiary of Pinnacle West Capital Corporation. The negative outlook is primarily a reflection of APS' continued need for rate increases in a regulatory arena that has historically been challenging. Given APS' current significant capital expenditure program, the company will require continued, timely regulatory support to maintain credit metrics that are appropriate for its rating.

The most important drivers of the rating and outlook are as follows:

Challenging Regulatory Environment

Almost all of APS' operations are regulated which is generally viewed as positive for credit quality as regulated cash flows tend to be more stable and predictable than those of unregulated companies. This key factor is tempered somewhat by the historically challenging regulatory environment in Arizona, which Moody's ranks as below average for U.S. regulatory jurisdictions in terms of supportiveness or predictability and stability of regulated cash flows.

APS' operations are regulated by the Arizona Corporation Commission (ACC), an elected commission that has tended to render its decisions after prolonged consideration. APS' rate case activity is illustrative of an environment where there has tended to be below average assurance of timely recovery of costs and the ability to earn a reasonable return on investment. APS' 2003 rate case was not concluded until April 2005, and the increase received was less than half of the amount requested; the significant delay and relatively modest allowed increase resulted in the need for APS to quickly file another rate case in January 2006.

APS' January 2006 rate case was decided somewhat quicker with a decision rendered in June 2007 wherein the utility received approximately three quarters of its requested increase; however, the allowed increase was almost entirely related to increased costs for fuel and purchased power. The 2007 decision included a significantly improved mechanism for the recovery of fuel and purchased power costs, incorporating a forward estimate of fuel costs in addition to the continued recovery of past deferrals. Fuel and purchased power costs have been among APS' most volatile operating expenses and Moody's views the ACC's recent approach to this problem as supportive of the utility's credit profile. Nevertheless, as part of the June decision, the ACC approved a severely limited percentage of APS' requested revenue increase for non-fuel items, including capital investment ($7 million versus a request of approximately $120 million). Given APS' growth rate, and its associated need for increased capital spending, this remains an area of concern for credit quality. Moody's believes APS will need to seek additional rate relief in the near-to-medium term.

In its June order, the ACC requested that APS propose mechanisms that could potentially allow growth to pay for itself, rather than being paid by the current customer base. The ACC is now considering an APS proposed amendment to its line extension schedule, or "hook-up-fees", that could potentially provide a relatively timely source of funding for growth related capital investment and potentially reduce the size of, or extend the time before, APS' next general rate case.

Growing Service Territory

APS' rating also recognizes the on-going strong growth in its service territory. In 2007, customer growth has been approximately 3%. Although somewhat below the 4-5% pace experienced in 2005 and 2006, growth is still significantly higher than the national average and is expected to remain around this level over the medium term. APS' increasing customer base has resulted in a continuing need for capital investment, but it also provides a source of revenue growth outside of base rate increases which could be expected to improve financial metrics assuming there is relatively timely recovery of increased growth related investment and fuel and purchased power costs.

APS' currently proposed amendment to its line extension schedule, if accepted, could shift some of the costs of growth to those new customers directly responsible for the increased costs, reducing the negative impacts of continued growth on APS going forward.

Financial Metrics

APS' key financial metrics reflect the fact that it has been unable to recover fully increased costs for fuel, purchased power and capital spending on a timely basis. For example, the ratio of cash from operations prior to changes in current assets and liabilities (CFO pre-WC) to adjusted debt (incorporating Moody's standard analytic adjustments) dropped into the mid-teens in 2004 and 2005 and then moving to the upper-teens and low 20% range in 2006 and 2007 as fuel recovery improved. These metrics are toward the middle of the 13% to 25% range identified in Moody's Rating Methodology for Global Electric Utilities for Baa rated entities on a stand-alone basis within the medium risk category and suggests a rating that could be Baa3 or Baa2. The Baa2 rating considers the potential for key financial ratios to remain in the ranges demonstrated in 2006 and 2007 if regulatory treatment is supportive of timely cost recovery, and if capital expenditures are financed in a manner that is also supportive of APS financial strength and flexibility. The negative outlook reflects Moody's concern with the potential for metrics to return to the ranges demonstrated in 2004 and 2005 over the next 12 - 18 months which could warrant a downward revision in the ratings. In general, Moody's would look for APS to have financial metrics that are somewhat stronger than comparably rated utility operating companies that operate in more supportive regulatory environments.

Subsidiary of Pinnacle West

Pinnacle, APS' parent company, conducts a modest amount of non-regulated activities including power marketing and trading, sales of energy related products and services, and residential and commercial real estate development through subsidiaries including SunCor Development Company (real estate). However, for the past several years almost all of Pinnacle's cash from operations has been generated by APS. Over the near-to-medium term, Pinnacle's non-regulated businesses, are not expected to meaningfully contribute to, or detract from, consolidated cash flows. Although residential real estate sales have slowed considerably in 2006 and 2007, Pinnacle's joint venture strategy, combined with its successfully completed asset sales program (implemented 2003-2005) has reduced its exposure to this volatile sector. The parent company also maintains a modest amount of leverage with holding company debt at less than 10% of consolidated debt.

Liquidity

APS' Prime-2 short-term rating for commercial paper reflects the relatively stable and predictable cash flow provided by its regulated electric utility operations.

For the twelve months ended September 30, 2007, APS' cash flow from operations of approximately $870 million covered approximately 65% of its outlays, including capital expenditures of approximately $860 million and dividends to Pinnacle of $170 million. The shortfall was funded via a combination of internal and external sources of cash including $150 million of short term debt proceeds, approximately $40 million of equity contributions from Pinnacle and cash on hand.

APS is expected to expend approximately $950 million on capital investment in 2007 of which about 71% has been incurred through the nine months ended September 30, 2007. Going forward, capital expenditures are expected to range from $1.0 to 1.1 billion per year, primarily to expand APS' transmission and distribution network to meet growing customer needs, but also to upgrade its existing utility properties and for other environmental purposes. Funding for these increased capital expenditures is expected to be provided via a combination of internal and external sources of cash, including operating cash flow, equity contributions from Pinnacle and long and short term debt financing.

Over the last several years, APS has paid dividends to Pinnacle of $170 million per year. While APS' dividends are expected to remain unchanged in 2007, Moody's expects them to increase moderately over the medium term.

APS' pattern of cash flow is seasonal as the peak of electric demand occurs during the summer months due to high air conditioning load that exists in its service territory. As a result, the bulk of its commercial paper borrowings typically occur in the second and third quarters of each year. On October 30, 2007, the ACC approved APS' request to increase short-term borrowings in order to meet growing cash requirements particularly for natural gas and power purchases. As of September 30, 2007, APS had no commercial paper outstanding, but had $150 of short-term debt outstanding under its revolving credit facility as those borrowing rates were lower than the Prime-2 CP rates available in the CP market due to the negative impact of this summer's "credit crunch".

APS has historically maintained a very modest level of cash on its balance sheet; as of September 30, 2007, APS had reported cash and cash equivalents of approximately $37 million.

APS' commercial paper program is sized at $250 million and is currently supported by two committed lines of credit totaling $900 million, a $400 million line that expires in December 2010 and a $500 million line that expires in September 2011. As of September 30, 2007, APS' overall availability under these credit facilities was $750 million. Both credit agreements have one financial covenant that requires the ratio of debt to total capitalization not to exceed 65%. As of September 30, 2007, APS' debt to total capitalization ratio, calculated in accordance with the credit documents, was approximately 46%. The credit agreements do not require a Material Adverse Change (MAC) representation for revolver borrowings. No rating triggers exist in any APS credit facilities though interest costs may increase under various financing agreements if a downgrade occurs. APS nearest long term debt maturity is $400 million of unsecured notes due in 2011. In 2010, APS must replace letters of credit supporting approximately $200 million of variable rate pollution control bonds.

APS' Prime-2 rating for its short term obligations assumes that the company will manage the amount of commercial paper and other near term obligations outstanding within the limits of its readily available sources of cash, including its committeed bank credit facilities.

Recent Events

Palo Verde

The operational performance of the 3,800 MW APS operated Palo Verde nuclear generating facility (which provides approximately 1,100 MWs to APS), improved significantly in 2007. As of September 30, 2007, Palo Verde's year-to-date capacity factor was 86%, versus 71% for 2006 and 77% for 2005.

However, as a result of a February 2007 "white" finding by the Nuclear Regulatory Commission (NRC) involving emergency diesel generators at Palo Verde Unit 3 (PVU3), in combination with a "yellow" finding in 2004 relating to its safety injection systems, PVU3 was placed into the "multiple/repetitive degraded cornerstone" column of the NRC's action matrix, which has resulted in an enhanced inspection regimen and some increased operating costs for APS as it seeks to improve its processes at all three Palo Verde units. In June 2007, the NRC issued an initial confirmatory action letter confirming APS' commitments regarding specific actions APS will take to improve Palo Verde's performance, and from October through November a team of NRC inspectors performed on-site in-depth inspections. APS expects to be informed of the NRC's findings in late December 2007 or early January 2008, and based on the NRC's findings, will make additional modifications to its improvement plan in 2008.

Rating Outlook

APS' negative outlook reflects Moody's view that based on APS' significant capital expenditure plans, absent any relatively near term supportive regulatory intervention or cost or leverage reductions, credit metrics and financial flexibility are likely to weaken over the near-to-medium term.

What Could Change the Rating - Up

In light of the negative outlook, APS' rating is not likely to be revised upward in the near-to-medium term. The rating outlook could be stabilized if regulatory treatment is supportive, or there were to be material reductions in costs or leverage such that Moody's could anticipate key financial ratios remaining near the levels demonstrated in 2007, if for example, a ratio of CFO pre-WC to adjusted debt could be maintained in the high teens to low twenty percent range.

What Could Change the Rating - Down

A downgrade could result if Palo Verde experiences an extended outage and APS is unable to recover, in a timely manner, higher maintenance and purchased power costs, or if APS' regulatory lag for capital spending does not improve. A downgrade could result if Moody's expects a weakening of financial metrics, if for example, the ratio of CFO pre-WC to adjusted debt would remain in the mid-teens for an extended period.

Rating Factors

Arizona Public Service Company
62000

Select Key Ratios for Global Regulated Electric Utilities

Rating	Aa	Aa	A	A	Baa	Baa	Ba	Ba
Level of Business Risk	Medium	Low	Medium	Low	Medium	Low	Medium	Low
CFO pre-W/C to Interest (x) [1]	>6	>5	3.5-6.0	3.0-5.7	2.7-5.0	2-4.0	<2.5	<2
CFO pre-W/C to Debt (%) [1]	>30	>22	22-30	12-22	13-25	5-13	<13	<5
CFO pre-W/C - Dividends to Debt (%) [1]	>25	>20	13-25	9-20	8-20	3-10	<10	<3
Total Debt to Book Capitalization (%)	<40	<50	40-60	50-70	50-70	60-75	>60	>70

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

Moody's Investors Service

Global Credit Research
Issuer Comment
23 FEB 2007

Issuer Comment: Arizona Public Service Company

Moody's comments on NRC's "white" finding at Palo Verde Nuclear Plant

Moody's Investors Service views the Nuclear Regulatory Commission (NRC)'s "white" finding at the conclusion of its inspection relating to the failure of Palo Verde Unit 3's emergency diesel generators as negative to the credit quality of Arizona Public Service Company (APS: senior unsecured Baa2), the operator and its parent, Pinnacle West Capital Corporation (Pinnacle: senior unsecured Baa3, but not material enough to impact the rating of APS or Pinnacle at this time. Moody's views the "white" finding by the NRC as a negative development in that it will subject APS to closer NRC oversight and additional costs for some time; however, at this time, given the magnitude of these expected expenditures, the potential impact to future cash flow and to the resulting credit metrics should be relatively modest. The rating outlook for both APS and Pinnacle remains negative.

On February 22, 2007, the NRC concluded its special inspection into the failure of emergency diesel generators at Palo Verde Unit 3 which had occurred during routine testing on July 25 and September 22, 2006. The "white" finding is given in conjunction with the NRC's reactor oversight process in which inspection findings are assigned a color that indicates safety significance. Findings with very low safety significance are labeled "green", "white" findings have low to moderate safety significance, "yellow" findings have substantial safety significance, and "red" findings have high safety significance. The NRC issued its preliminary "white" finding in December 2006. The final "white" finding considered APS' responses, and although performance improvement initiatives that were begun in the fourth quarter 2006 were noted, the NRC ultimately concluded that a "white" finding was still appropriate.

In connection with the "white" finding, the NRC will use its NRC Action Matrix to determine the most appropriate response, including any increase in NRC oversight, or actions APS needs to take in response to the most recent performance deficiencies. This "white" finding, coupled with a previous "yellow" finding relating to a 2004 incident involving its emergency cooling system, will place one or more of the Palo Verde's units in the fourth or "multiple/repetitive degraded cornerstone" column of the NRC's Action Matrix, which will result in an enhanced NRC inspection regimen.

APS has been operating under increased NRC supervision since 2004 when it received the "yellow" finding noted above. For this new "white" finding the NRC cites continued concerns relating to APS' procedures and problem solving processes. APS has been working to address these issues, and the company will continue to incur additional expenditures as it further implements performance improvement initiatives and responds to specific NRC requests. Moody's believes that, all else being equal, the amount of additional expenditures that are likely to be incurred would not be material to the ratings of APS or Pinnacle.

The rating outlooks for APS and Pinnacle remain negative and continue to primarily reflect the potential for downward pressure on ratings if regulatory outcomes in the pending APS general rate case do not provide for relatively timely recovery of increased costs. The ratings could also be revised downward if there were to be additional operating challenges at Palo Verde, as a result of increased NRC oversight, or otherwise, which result in a significant sustained increase in operating costs.

Headquartered in Phoenix Arizona, Pinnacle West Capital Corporation provides electric service to a substantial portion of the state of Arizona, sells energy-related products and services, and develops residential, commercial and industrial real estate. While Pinnacle conducts these business though separate subsidiaries, wholly owned Arizona Public Service Company is its principal subsidiary.

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Moody's Investors Service

Global Credit Research
Issuer Comment
21 JUN 2007

Issuer Comment: Arizona Public Service Company

Moody's comments on the Arizona Corporation Commission's vote in Arizona Public Service Company's rate case

Moody's Investors Service views the Arizona Corporation Commission's (ACC) vote to approve, with certain modifications, the recommended order of its Chief Administrative Law Judge (ALJ) in Arizona Public Service Company's (APS: Baa2 senior unsecured, negative outlook) as neutral to the credit quality of APS and its parent company Pinnacle West Capital Corporation (PNW: Baa3 senior unsecured, negative outlook) and having no impact on the rating or outlook of APS or PNW at this time.

On June 19, 2007, the ACC voted to approve an increase in APS' annual retail revenues by approximately $322 million, or approximately three quarters of the amount requested by APS. Of the $322 million, $315 million is for recovery of increased costs for fuel and purchased power.

The amended order includes mechanisms that are intended to provide significantly improved recovery of APS fuel and purchased power costs. Moody's views these items including, a base fuel rate set at APS' estimated of 2007 costs, the continuation of the interim Power Supply Adjustor (PSA), and the implementation of a prospective PSA, as positive for the credit quality of APS and Pinnacle, and over the near term, supportive of their existing credit ratings. However, the rate increase approved by the ACC is less than the full amount requested by APS and it does not include any of the revenue enhancement proposals introduced by the company offered to assure more timely recovery of non-fuel related costs incurred to serve its rapidly growing load.

Given the significant amount of capital expenditures that APS is planning to spend for its growing load, Moody's believes it is likely the company will need to seek additional rate relief in the near term. Based on the time that it has recently taken to conclude APS' general rate cases (the June 2003 case was concluded in April 2005; the current case was initially filed November 2005), we believe there remains a significant risk that credit metrics will weaken over the medium term due to the continued lag in recovery of non-fuel related costs.

Moody's anticipates that in the near term, APS and Pinnacle's financial credit metrics will remain at the lower end of the ranges considered appropriate for their current ratings. For example, we have indicated that the outlooks could be stabilized at the current ratings levels if the ratio of cash flow from operations excluding changes in working capital to adjusted debt (adjusted in accordance with Moody's standard analytical adjustments) ((CFO x WC)/Debt) remained in the range of 17-20% at APS and 15-18% at Pinnacle, on a sustainable basis.

The outlooks for both APS and Pinnacle remain negative reflecting our assessment of the continuing regulatory risk, their most recent financial position, and their significant projected capital expenditure requirements. The order approved by the ACC provides limited "headroom" or financial flexibility for APS and Pinnacle to address any unanticipated adverse developments that might occur in the future such as increased expenses due to significant operational difficulties, material cost overruns on capital expenditure programs or prolonged rate case outcomes.

Headquartered in Phoenix Arizona, Pinnacle West Capital Corporation provides electric service to a substantial portion of the state of Arizona, sells energy-related products and services, and develops residential, commercial and industrial real estate. While Pinnacle conducts these businesses through separate subsidiaries, wholly owned Arizona Public Service Company is its principal subsidiary.

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Moody's Investors Service

Global Credit Research
Issuer Comment
7 MAY 2007

Issuer Comment: Arizona Public Service Company

Moody's comments on ACC Administrative Law Judge's recommendation in Arizona Public Service rate case

Moody's Investor's Service views the recommendation of the Arizona Corporation Commission's (ACC) Chief Administrative Law Judge (ALJ) in Arizona Public Service Company's (APS: Baa2 senior unsecured, negative outlook) pending rate case as neutral to the credit quality of APS and its parent company Pinnacle West Capital Corporation (PNW: Baa3 senior unsecured, negative outlook) and having no impact on the rating or outlook of APS or PNW at this time.

On April 27, 2007, the ACC's Chief ALJ issued an order recommending that APS be granted an electric revenue increase of approximate $286 million, or approximately two-thirds of the $435 million requested by APS. Although the ALJ's recommended increase is significantly lower than APS' requested amount, the order also proposed that a prospective Power Supply Adjustor (PSA) be included in APS rates. A prospective PSA should provide more timely recovery of fuel and purchased power costs, which should improve cash flows, and reduce the need to finance significant deferral balances. If the ALJ order is accepted as written, Moody's anticipates that in the near term, APS and Pinnacle's financial credit metrics would remain at the lower end of the ranges considered appropriate for their ratings. For example, we have indicated that the outlooks could be stabilized at the current ratings levels if we believed credit metrics such as the ratio of cash flow from operations excluding changes in working capital to adjusted debt (adjusted in accordance with Moody's standard analytical adjustments) ((CFO x WC)/Debt) would remain in the range of 17-20% at APS and 15-18% at Pinnacle, on a sustainable basis.

The ALJ also recommended against all of the revenue enhancement proposals introduced by APS for consideration as a means of creating more timely recovery of non-fuel related costs. Rather than adopting any of the proposals, the ALJ recommended that APS continue to seek recovery of non-fuel costs via the regular rate case process. Given the significant amount of capital expenditures that APS is planning to provide for its growing load, Moody's believes it is likely the company will need to seek additional rate relief in the near term.

Based on the time that it has recently taken to conclude APS' general rate cases (the June 2003 case was concluded in April 2005; the current case was initially filed November 2005), we believe there remains a significant risk that credit metrics will weaken over the medium term. As a result, the outlooks for both APS and Pinnacle remain negative reflecting our assessment of the regulatory overhang risk still facing the companies, their most recent financial position, and their significant projected capital expenditure requirements. Moody's recognizes that the final ACC decision may ultimately be different from the recommended order, and notes that the recommended order would likely result in limited "headroom" or financial flexibility for APS and Pinnacle to address any unanticipated adverse developments such as increased expenses due to significant operational difficulties, material cost overruns on capital expenditure programs or prolonged rate case outcomes.

Headquartered in Phoenix Arizona, Pinnacle West Capital Corporation provides electric service to a substantial portion of the state of Arizona, sells energy-related products and services, and develops residential, commercial and industrial real estate. While Pinnacle conducts these businesses through separate subsidiaries, wholly owned Arizona Public Service Company is its principal subsidiary.

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Global Power
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Credit Analysis

Arizona Public Service Company
(Subsidiary of Pinnacle West Capital Corporation)

Ratings

Security Class	Current Rating
Long-Term IDR	BBB–
Senior Unsecured Notes	BBB
Short-Term IDR	F3
Commercial Paper	F3

Outlook

Stable

Financial Data

Arizona Public Service Company
($ Mil.)

	LTM 9/30/07	2006
Revenues	2,883	2,659
Gross Margin	1,767	1,689
Cash Flow From Operations	669	394
Operating EBITDA	980	922
Total Debt	3,463	3,317
Total Capitalization	6,846	6,525
ROE (%)	9.1	8.7
Capex/Depreciation (%)	243	190

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Related Research

- *Credit Update, Pinnacle West Capital Corp., dated Jan. 23, 2008.*
- *Press Release, "Fitch: Arizona Commission Ruling in GRC Supports Arizona Public Service Co. & PNW Ratings," dated June 21, 2007.*
- *Press Release, "Fitch Lowers PNW & APS' Sr. Unsecured Ratings to 'BBB-' & 'BBB', Respectively; Outlook Stable," dated Jan. 30, 2006.*

Rating Rationale

- The ratings of Arizona Public Service Company (APS) are supported by the June 2007 Arizona Corporation Commission (ACC) order in APS's general rate case (GRC), which increased revenue $322 million and improved its power supply adjustor.
- Fitch estimates funds from operations to interest expense will approximate 4.6 times (x) in 2007 and 4.3x in 2008, consistent with low 'BBB' credit metrics.
- Regulatory lag, combined with APS's large capital expenditure program, is expected to result in lower operating profit, cash flow and credit metrics in 2008, with anticipated stabilization and modest improvement in 2009–2010, in Fitch's opinion.
- The Palo Verde Nuclear Generating Station's operating record has improved under new management in 2007.

Key Rating Drivers

- APS's large capital expenditure program will require ongoing rate increases to maintain current creditworthiness.
- Attrition due to regulatory lag could lead to significant deterioration in projected 2009 earnings and cash flows, resulting in credit rating downgrades.
- Adoption of a proposed line extension tariff would enhance cash collections and ameliorate potential financial erosion in 2008–2010.
- Fitch estimates that APS's return on equity (ROE) will decline to the 6%–7% range in 2008, well below its authorized 10.75% return, which could result in higher capital costs.

Recent Events

Despite the $322 million (15%) rate increase authorized by the ACC in June 2007, APS's large capital investment program is expected to require further rate hikes to maintain current creditworthiness. Fitch expects APS to file a GRC in early 2008, depending on resolution of the Schedule 3 tariff review.

In October 2007, APS requested a non-refundable line extension tariff that, if approved by the commission on a timely basis, could result in pretax cash of $50 million–$191 million per annum from 2008–2010. Fitch believes the proposed Schedule 3 tariff change could ameliorate the adverse effects of regulatory lag through 2010.

Liquidity and Debt Structure

At the end of the third quarter of 2007, APS had cash and cash equivalents totaling $37 million and total debt of $3.0 billion, composed of $2.9 billion of long-term debt and $151 million of short-term debt and current maturities. On an adjusted basis, debt-to-FFO was 4.4x as of Sept. 30, 2007. Short-term access to capital is provided by APS's $250 million commercial paper program, which is backed by a $400 million revolving credit facility that matures in December 2010. In addition, APS has negotiated a $500 million bank agreement scheduled to mature September 2011, to meet its power supply-related liquidity needs, including collateral requirements. APS's large capital program is expected to require significant external funding. APS's next scheduled debt maturity is in October 2011 when $400 million of 6 3/8% senior notes are due.

Large Capital Expenditure Program

APS is in the midst of a major investment cycle and is expected to file for rate increases on a regular basis over the next several years. APS is expected to invest approximately $1 billion per annum from 2007–2009 to meet load growth and reliability requirements. Over that same time period, Fitch estimates that operating cash flow will approximate 70%–80% of projected capital expenditures and that significant external financing, both debt and equity, will be required to fund the program. Capital expenditures at APS are expected to increase 50% to $3 billion during 2007–2009, from $2 billion during 2004–2006, with most of the increased spending directed to transmission, distribution and environmental projects.

Arizona Public Service Company Forecasted Capital Expenditures
($ Mil.)

	2007	2008	2009	Total, 2007–2009
Distribution	360	410	460	1,230
Transmission	170	200	290	660
Generation	390	300	340	1,030
Other	30	40	40	110
Total	950	950	1,130	3,030

Source: Company filings.

Schedule 3 Line Extension Tariff Filing

As required by the ACC's June 2007 order in APS's GRC, the utility filed to revise its Schedule 3 line extension tariff with the ACC in October 2007 to eliminate free line extension footage. Under the proposed change, new customers would be required to pay a non-refundable hook-up fee of $3,500–$5,000 per new meter set.

Grandfathering provisions are expected to exempt any person that has already filed for a line extension. As a result, the full cash benefit of the tariff is not likely to be realized by APS until 2010. APS's pretax cash collection estimates are presented at right.

Pretax Cash Collection Estimates
($ Mil.)

2008	50
2009	117
2010	159–191

Source: Company filings.

The company supports "miscellaneous revenue" accounting for the change in Schedule 3 rates and the ACC staff favors a "contribution in aid of construction (CIAC)" approach. Under the former approach, collections would be reported as revenue, resulting in higher margin and operating cash flow and improving credit metrics. If treated as CIAC, the fee would be an offset to capital investment, reducing rate-base growth and would not be reflected in the income statement or operating cash flows. Fitch believes APS's credit metrics would strengthen more meaningfully under the miscellaneous revenue method compared to CIAC accounting.

The item was on the ACC's agenda for its November 2007 meeting. However, in a negative development, APS's line extension tariff filing was removed from the ACC's November 2007 open meeting agenda. Subsequent commissioner letters indicate that the issue may go to hearings, which would result in further delay in rendering a decision in the proceeding.

General Rate Case

In June 2007, the ACC authorized a $322 million (15%) retail rate increase based on a 10.75% ROE and a 55% equity ratio in APS's 2005 GRC. Positively, the ACC modified the

PSA to include prospective fuel and purchased power costs which, along with the company's hedging policies, should significantly ameliorate commodity price risk.

In Fitch's opinion, the ACC's rejection of the utility's request for attrition adjustments, construction work in progress and accelerated depreciation in its 2005 GRC filing is a negative development for APS investors, in light of the utility's above-average growth rate and 2007–2009 capital requirements estimated at approximately $3 billion. In Fitch's view, APS's credit quality will turn on its ability to operate Palo Verde and its other generation facilities effectively and work with the ACC to reduce regulatory lag.

Fitch expects APS, depending on the outcome of its pending Schedule 3 line extension tariff proceeding, to file a new GRC in the first quarter of 2008.

Authorized and Estimated Earned Returns

APS continues to charge rates based on a 2005 test year and will continue to do so until a final order is issued in its next GRC. The resulting gap between the costs currently being collected in rates and costs incurred could lead to meaningful attrition to APS's earnings, cash flows and credit metrics in 2009. Fitch projects APS's 2008 earned ROE will decline to approximately 6.5%, from an estimated 8.5% in 2007, well below its authorized level of 10.75%. However, further delay in APS's anticipated GRC could lead to further deterioration in 2009. All else being equal, low earned returns on investment are likely to result in higher financing costs.

Palo Verde Nuclear Generating Station Update

In February 2007, PVNGS Unit 3 was placed by the Nuclear Regulatory Commission (NRC) in Column 4—the repetitive degraded cornerstone column, its highest operating oversight level for a nuclear plant. Fitch notes that the Palo Verde Nuclear Generating Station (PVNGS) continues to operate and that APS has changed senior management at the facility and taken significant action to address its operating difficulties. Fitch expects the plant to continue under elevated NRC scrutiny through 2009.

APS recorded fuel cost deferrals of $45 million in 2005 and $79 million in 2006 related to outages and periods of low power operation at APS's PVNGS Unit 1. The operating difficulties were due to excessive vibration levels in the plant's cooling system. The ACC authorized recovery of $34 million, or approximately 76% of the 2005 deferral balance, through a temporary surcharge and disallowed the remaining $14 million as imprudent.

The commission directed the ACC staff to conduct a prudence audit of the 2006 PVNGS Unit 1 outage. In October 2007, the staff filed a report with the ACC that concludes that APS's response to the vibration was "reasonable and prudent."

Financing Order

On Oct. 31, 2007, the ACC issued a financing order approving an increase in APS's long-term borrowing limit by $1 billion to $4.2 billion. The financing order authorizes APS to issue short-term debt up to 7% of its total capitalization, or approximately $440 million currently. In addition, the financing order allows APS to exceed the short-term debt limit of 7% of its total capitalization by up to $500 million, as long as the additional short-term debt is used to purchase natural gas or power, including collateral calls for hedged positions. Thus, APS's limit on short-term debt under the financing order for APS is approximately $940 million.

Financial Summary — Arizona Public Service Company
($ Mil., Years Ended Dec. 31)

	LTM 9/30/07	2006	2005	2004	2003	2002
Fundamental Ratios (x)						
Funds from Operations/Interest Expense	4.9	3.6	4.4	3.3	4.5	5.5
Cash Flow from Operations/Interest Expense	4.3	3.1	5.1	5.0	5.3	5.2
Debt/Funds from Operations	4.4	6.8	5.0	7.7	4.9	3.6
Operating EBIT/Interest Expense	3.1	3.0	3.2	2.6	2.3	2.9
Operating EBITDA/Interest Expense	4.9	4.9	5.1	4.5	4.4	5.3
Debt/Operating EBITDA	3.5	3.6	3.4	4.0	3.9	3.1
Common Dividend Payout (%)	57.3	63.0	99.7	85.2	94.0	85.3
Internal Cash/Capital Expenditures (%)	56.2	33.1	86.8	103.0	136.4	109.0
Capital Expenditures/Depreciation (%)	243.4	189.6	193.2	156.0	112.5	122.6
Profitability						
Revenues	2,883	2,659	2,271	2,197	2,105	1,936
Net Revenues	1,767	1,689	1,582	1,434	1,402	1,465
Operating and Maintenance Expense	680	666	592	540	514	496
Operating EBITDA	980	922	891	808	811	894
Depreciation and Amortization Expense	361	353	325	337	389	400
Operating EBIT	619	568	566	471	422	495
Gross Interest Expense	201	190	176	180	183	169
Net Income for Common	297	270	170	200	181	199
Operating Maintenance Expense % of Net Revenues	38.5	39.4	37.4	37.7	36.6	33.8
Operating EBIT % of Net Revenues	35.0	33.7	35.8	32.8	30.1	33.8
Cash Flow						
Cash Flow from Operations	669	394	722	718	777	705
Change in Working Capital	(118)	(91)	115	297	132	(61)
Funds from Operations	787	485	607	421	645	765
Dividends	(170)	(170)	(170)	(170)	(170)	(170)
Capital Expenditures	(879)	(669)	(628)	(525)	(438)	(490)
Free Cash Flow	(380)	(446)	(76)	23	169	44
Net Other Investment Cash Flow	(11)	(12)	(13)	3	(502)	30
Net Change in Debt	65	309	(156)	92	402	(48)
Net Change in Equity	42	213	250	0	0	0
Capital Structure						
Short-Term Debt	150	0	0	0	0	0
Long-Term Debt	3,313	3,317	3,033	3,220	3,146	2,743
Total Debt	3,463	3,317	3,033	3,220	3,146	2,743
Preferred and Minority Equity	0	0	0	0	0	0
Common Equity	3,383	3,207	2,985	2,232	2,204	2,159
Total Capital	6,846	6,525	6,018	5,452	5,350	4,903
Total Debt/Total Capital (%)	50.6	50.8	50.4	59.1	58.8	56.0
Preferred and Minority Equity/Total Capital (%)	0.0	0.0	0.0	0.0	0.0	0.0
Common Equity/Total Capital (%)	49.4	49.2	49.6	40.9	41.2	44.0

Note: Numbers may not add due to rounding. Numbers are adjusted for interest and principal payments on transition property securitization certificates. Long-term debt includes trust preferred securities.
Source: Financial data obtained from SNL Energy Information System, provided under license by SNL Financial, LC of Charlottesville, VA.

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Fitch Revises Pinnacle West's Outlook to Negative; Affirms 'BBB-' IDR Ratings

21 Dec 2007 10:15 AM (EST)

Fitch Ratings-New York-21 December 2007: Fitch Ratings has taken the following rating actions on the long-term Issuer Default Ratings (IDRs) and outstanding debt of Pinnacle West Capital Corporation (PNW) and its core electric utility subsidiary, Arizona Public Service Co. (APS) as shown below:

Pinnacle West Capital:
--Long-term IDR affirmed at 'BBB-';
--Short-term IDR affirmed at 'F3';
--Commercial paper affirmed at 'F3'.

Arizona Public Service Co.:
--Long-term IDR affirmed at 'BBB-';
--Short-term IDR downgraded to 'F3' from 'F2';
--Senior unsecured affirmed at 'BBB';
--Commercial paper downgraded to 'F3' from 'F2'.

PVNGS II Funding Corp.
--Secured lease obligation bonds affirmed at 'BBB'.

The short-term ratings downgrade on APS reflects consistency with Fitch's short-term/long-term rating linkage practices. Fitch has also revised PNW's Rating Outlook to Negative from Stable. The Rating Outlook for APS remains Stable. Approximately $4 billion of debt securities are affected by the rating action.

APS' ratings and Stable Rating Outlook consider the final decision in the utility's 2005 general rate case issued by the Arizona Corporation Commission (ACC) in June 2007, which include constructive changes to the utility's power supply adjustor (PSA) included in the ACC order. In addition, the ratings assume that external funds required by APS to meet growing capital investment will be composed of a balanced mix of equity and debt. The APS Outlook is predicated on future regulatory outcomes that support low-investment grade credit metrics at the utility through 2010, based on Fitch estimates. The PNW Outlook revision to Negative is a function of the holding company's somewhat weak credit metrics relative to the rating category and the potential for further deterioration due to regulatory lag and lower real-estate margin.

Fitch notes that earnings and cash flow attrition due to regulatory lag and/or unanticipated disallowances is a significant challenge to the sustainability of PNW and APS's investment grade credit ratings. Revenue increases below our expectations or undue delay would likely result in credit rating downgrades.

APS filed a request for a change to its Schedule 3 line extension tariff that Fitch estimates could raise incremental pre-tax cash of $50-150 million per annum 2008-2010. Approval of the proposed, non refundable line extension tariff revenue in the near-term could ameliorate concerns regarding earnings and cash flow attrition due to regulatory lag through 2009. In a negative development, the ACC deferred consideration of the issue (which had been scheduled for November) and may conduct hearings on the matter.

Fitch expects APS to file its next GRC in 2008 to recover significant capital expenditures. As 2008 approaches, APS is collecting non-fuel rates based on a 2005 test year and will continue to do so until a final decision is rendered in its anticipated GRC, despite rapidly mounting fixed costs. Slippage of a final ACC ruling to late-summer or the fourth quarter of 2009 could result in meaningful PNW and APS earnings and cash flow attrition, erosion of estimated 2009 credit metrics and ultimately to negative credit rating actions.

In June 2007, the ACC authorized a $322 million (15%) retail rate increase based on a 10.75% return on equity (ROE) and a 55% equity ratio in APS's 2005 GRC order, based on a 2005 test year. Positively, the ACC modified the PSA to include prospective fuel and purchase power costs, which along with the company's hedging policies should significantly ameliorate commodity price risk.

In Fitch's opinion, the ACC's rejection of the utility's request for attrition adjustments, construction work in progress and accelerated depreciation in its 2005 GRC filing is a negative development for PNW and APS investors, in light of the utility's 2007 - 2009 capital requirements, estimated at approximately $3 billion. Fitch believes APS' credit quality will turn on its ability to operate effectively, prudently meet rapid service territory growth requirements and work with the ACC to reduce regulatory lag.

APS' fossil generation has generally performed well in recent years. However, deterioration in safety margin at Palo Verde Nuclear Generating

APS13043
Page 1 of 2

Station (PVNGS) and unscheduled outages experienced in 2005 and 2006 are a concern for investors. PVNGS Unit 3 was placed by the Nuclear Regulatory Commission (NRC) in Column 4 - the repetitive degraded cornerstone column, its highest operating oversight level for a nuclear plant in February 2007. Fitch notes that PVNGS continues to operate safely according to the NRC and that APS has changed senior management at the facility and taken significant action to address its operating difficulties.

The ratings also consider the potential negative implications of the ongoing downturn in the U.S housing sector on SunCor Development Co. (SunCor), PNW's real-estate development subsidiary. Fitch notes that SunCor represents a relatively small proportion of consolidated PNW results, approximately 13% of 2006 earnings before interest. SunCor exposure may be ameliorated by a legacy low-cost basis property portfolio.

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Fitch:Arizona Commission Ruling in GRC Supports Arizona Public Service Co. & PNW Ratings

Ratings
21 Jun 2007 8:41 AM (EDT)

Fitch Ratings-New York-21 June 2007: The recent Arizona Corporation Commission (ACC) bench ruling in Arizona Public Service Company's (APS) general rate case (GRC) is, in Fitch's opinion, supportive of the existing credit ratings of the utility and its corporate parent, Pinnacle West Capital, Inc. (PNW). PNW and APS's credit ratings are listed below.

Pinnacle West Capital
--Long-term Issuer Default Rating (IDR) 'BBB-';
--Short-term Issuer Default Rating (IDR) 'F3'.

Arizona Public Service Co.
--Long-term Issuer Default Rating (IDR) 'BBB-';
--Short-term Issuer Default Rating (IDR) 'F2';
--Senior unsecured debt 'BBB'.

The Rating Outlook is Stable.

On June 19, 2007, the ACC issued a bench ruling in APS's GRC authorizing a $322 million retail base revenue increase (15%) based on a 10.75% authorized return on equity (ROE) and a 55% equity ratio. APS originally sought a 20% rate increase. New rates will be effective July 1, 2007.

Fitch notes that the ACC decision rejected APS's request for accelerated depreciation, inclusion of construction work in progress in rate base and an attrition adjustment. The inability of APS to receive timely recovery of its large capex program could pressure future credit metrics.

The ACC decision incorporates a base rate for fuel and purchased power costs of 3.25 cents per kilowatt hour (kwh), which compares favorably to the administrative law judge's 3.12 cents per kwh recommendation. The non-fuel portion of the rate increase was $7 million.

Importantly, the commission decision addressed significant issues with regard to the utility's power supply adjustor (PSA) that, in Fitch's opinion, meaningfully improves the company's business risk profile. The PSA allows APS to defer and recover 90% of the variance in net power supply costs without filing a general rate case.

The ACC modifications to the PSA include use of forward estimates of fuel and purchase power costs in place of historic costs. Positively, the order removes a $776 million annual power supply cost cap and a four mil cumulative, lifetime limit on collection of net power supply cost deferrals.

The commission order continues a four mil limit (approximately $105 million) on the amount of incremental cash collections of deferred power supply costs in a given year. APS is able, at its option, to seek a mid-year change through the transition component of the PSA in the event of large variances in fuel and purchase power costs.

The ACC order disallowed recovery of approximately $14 million of a total of $48 million of deferred costs related to unplanned 2005 Palo Verde Nuclear Generating Station (PVNGS) outages, representing 29% of the total 2005 PVNGS deferred balance. The remainder will be collected via a special surcharge.

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Global Power
U.S. & Canada
Credit Update

Pinnacle West Capital Corp.

Ratings

Security Class	Current Rating
Long-Term IDR	BBB–
Short-Term IDR	F3
Commercial Paper	F3

Outlook

Negative

Financial Data

Pinnacle West Capital Corp.
($ Mil.)

	LTM 9/30/07	2006
Revenues	3,495	3.402
Gross Margin	2,099	2,150
Cash Flow From Operations	588	394
Operating EBITDA	1,025	1,008
Total Debt	4,038	3,738
Total Capitalization	7,607	7,184
ROE (%)	9.3	9.5
Capex/Depreciation (%)	253	212

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Related Research

- *Credit Analysis, Arizona Public Service Company, dated Jan. 23, 2008.*
- *Press Release, "Fitch: Arizona Commission Ruling in GRC Supports Arizona Public Service Co. & PNW Ratings," dated June 21, 2007.*
- *Press Release, "Fitch Lowers PNW & APS' Sr. Unsecured Ratings to 'BBB–' & 'BBB', Respectively; Outlook Stable," dated Jan. 30, 2006.*

Rating Rationale

- The ratings and recent Outlook revision is a function of Pinnacle West Capital Corp.'s (PNW) somewhat weak credit metrics relative to the rating category.
- The large capital expenditure program and related attrition due to regulatory lag at PNW's core electric utility subsidiary, Arizona Public Service Co. (APS), are likely to result in weakening credit metrics in 2008.
- Fitch estimates 2007 funds from operations (FFO)-to-interest expense of approximately 4.0 times (x) and debt-to-FFO of 5.7x.
- In a favorable development, the June 2007 Arizona Corporation Commission (ACC) order in APS's general rate case (GRC) increased revenue and meaningfully improved the utility's power supply adjustor.
- The contribution of PNW's real estate subsidiary, SunCor, to consolidated results is expected to decline due to the nationwide housing market downturn.

What Could Trigger a Downgrade?

- Regulatory lag and/or adverse rate case outcomes are primary concerns that could lead to deteriorating creditworthiness and downgrades in the near-to-intermediate term.
- A sharp, unanticipated increase in debt leverage.
- Significant deterioration in APS's generating plant performance.

Recent Events

Despite the $322 million (15%) rate increase authorized by the ACC in the utility's last rate case, APS's large capital expenditure program is expected to require further rate relief to maintain creditworthiness. Fitch expects APS to file its next GRC in Q108, depending on the outcome in the Schedule 3 tariff proceeding.

The potential adoption of a proposed, non-refundable line extension tariff by the ACC in the near-term would be a constructive event, in Fitch's opinion. The company estimates the proposed tariff could result in pre tax cash of $50 million–$191 million per annum 2008–2010. Approval of the tariff would mitigate regulatory lag.

Liquidity and Debt Structure

At the end the third quarter 2007, PNW had cash and cash equivalents totaling $44 million on its consolidated balance sheet and total debt of $3.6 billion. PNW has a $250 million commercial paper program backed by a $300 million revolving credit agreement. Parent company debt totaling $175 million was outstanding as of Sept. 30, 2007 and matures in February 2011.

Financial Summary — Pinnacle West Capital Corp.

($ Mil., Years Ended Dec. 31)

	LTM 9/30/07	2006	2005	2004	2003	2002
Fundamental Ratios (x)						
Funds from Operations/Interest Expense	3.7	2.9	4.6	3.6	5.1	4.9
Cash Flow from Operations/Interest Expense	3.4	2.7	4.4	5.0	5.0	5.0
Debt/Funds from Operations	6.2	8.7	4.5	6.8	4.2	4.4
Operating EBIT/Interest Expense	2.7	2.9	3.2	2.6	2.2	2.6
Operating EBITDA/Interest Expense	4.2	4.4	4.8	4.4	4.1	4.6
Debt/Operating EBITDA	3.9	3.7	3.4	4.1	4.2	3.8
Common Dividend Payout (%)	65.1	61.5	105.9	68.6	65.4	92.2
Internal Cash/Capital Expenditures (%)	40.4	25.3	83.4	124.3	102.7	80.1
Capital Expenditures/Depreciation (%)	253.4	211.5	187.5	140.5	166.5	218.6
Profitability						
Revenues	3,495	3,402	2,988	2,829	2,759	2,405
Net Revenues	2,099	2,150	2,100	1,941	1,897	1,873
Operating and Maintenance Expense	707	691	636	592	549	585
Operating EBITDA	1,025	1,008	1,033	940	942	1,007
Depreciation and Amortization Expense	369	359	348	392	435	422
Operating EBIT	656	649	685	549	507	585
Gross Interest Expense	242	227	216	214	227	221
Net Income for Common	323	327	176	243	241	149
Operating Maintenance Expense % of Net Revenues	33.7	32.1	30.3	30.5	28.9	31.2
Operating EBIT % of Net Revenues	31.3	30.2	32.6	28.3	26.7	31.2
Cash Flow						
Cash Flow from Operations	588	394	730	851	902	877
Change in Working Capital	(65)	(36)	(45)	289	(41)	17
Funds from Operations	652	429	775	562	943	860
Dividends	(210)	(201)	(187)	(167)	(157)	(138)
Capital Expenditures	(935)	(759)	(652)	(550)	(725)	(923)
Free Cash Flow	(557)	(566)	(108)	134	20	(183)
Net Other Investment Cash Flow	(26)	(25)	(12)	(19)	(39)	13
Net Change in Debt	179	240	(246)	(141)	115	17
Net Change in Equity	34	40	298	18	0	199
Capital Structure						
Short-Term Debt	274	36	16	71	86	228
Long-Term Debt	3,765	3,702	3,502	3,749	3,892	3,599
Total Debt	4,038	3,738	3,518	3,820	3,978	3,827
Preferred and Minority Equity	0	0	0	0	0	0
Common Equity	3,569	3,446	3,425	2,950	2,830	2,686
Total Capital	7,607	7,184	6,943	6,770	6,808	6,513
Total Debt/Total Capital (%)	53.1	52.0	50.7	56.4	58.4	58.8
Preferred and Minority Equity/Total Capital (%)	0.0	0.0	0.0	0.0	0.0	0.0
Common Equity/Total Capital (%)	46.9	48.0	49.3	43.6	41.6	41.2

Note: Numbers may not add due to rounding. Numbers are adjusted for interest and principal payments on transition property securitization certificates. Long-term debt includes trust preferred securities.
Source: Financial data obtained from SNL Energy Information System, provided under license by SNL Financial, LC of Charlottesville, VA.

STANDARD & POOR'S

RATINGSDIRECT®

June 25, 2008

Summary:
Arizona Public Service Co.

Primary Credit Analyst:
Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

Table Of Contents

Summary:

Arizona Public Service Co.

Credit Rating: BBB-/Stable/A-3

Rationale

Standard & Poor's Ratings Services today affirmed the 'BBB-' corporate credit rating assigned to Pinnacle West Capital Corporation (PWCC) and its utility, Arizona Public Service. The outlook is stable. The consolidated credit ratings of PWCC primarily reflect the operations of its largest subsidiary, APS, a regulated, electric utility serving about 1.1 million customers within its service territory, which spans roughly two-thirds of Arizona and includes about half of the Phoenix MSA. We view the business profile of PWCC and APS to be 'strong'. While the company continues to benefit from a number of favorable attributes including a good service territory, a reasonably balanced power supply portfolio and a good PSA. However, APS' continues to face significant regulatory challenges.

APS provided the company with about 92% of its consolidated net income in 2007. SunCor, PWCC's real estate development company, provided about 4%, but due to the significant real estate slowdown in the southwest, it is unlikely it will be a meaningful contributor of cash flows or income over the next several years. (Prior to the real estate downturn, our forecasts have conservatively limited earnings from this subsidiary due to the cyclic nature of its cash flows.) Other subsidiary operations include Pinnacle West Trading and Marketing, which contributed about 4% of consolidated net income in 2007. This subsidiary has since last year been minimizing trading operations. Its largest contract was serving all-requirements load for UNS Electric Inc., which ended in May 2008.

We view the financial profile of PWCC and APS to be 'aggressive', which reflects: year-end debt to total capitalization of 57% (adjusted for items such as power purchases and operating leases); heavy capital spending that is expected to drive negative free operating cash flow for the foreseeable future; cash flow weakness as a function of protracted rate cases; and, while modest, the presence of unregulated activities, which can be unpredictable in their earnings contributions.

Because the preponderance of cash flows for consolidated operations stems from APS, we expect financial performance will continue to be heavily dependent on regulatory outcomes. The conclusion of APS' last general rate case in June 2007 (filed in November 2005 and revised in early 2006) provided the company with mechanisms to recover legacy deferrals and speed the recovery of fuel costs going forward. This rate relief, in place for the last half of 2007, assisted the company in maintaining credit metrics roughly in line with past performance. Funds from operations (FFO) to total debt was about 16% at year-end, with FFO interest coverage around 4x. On a trailing 12-month basis the company's performance has been slightly above these levels, due in part to the federal tax stimulus package approved by the U.S. Congress earlier this year, which is expected to increase deferred taxes (which are added back to FFO and thus increase this total).

We expect APS to be in more or less continuous rate case mode for the next few years. Given APS' capital spending program, forecasted to be about $1.1 billion annually through 2010, the utility will need to file regular general rate cases to manage recovery of its investment. The use of a historical test year in Arizona, coupled with the fact that fully litigated rate cases take between 18 to 24 months to complete, is expected to result in no meaningful improvement in financial performance through 2009 and possibly beyond, depending on the timing and the

outcome of the company's current case.

APS filed its current rate case in March 2008. ACC staff requested that the company revise its filing to reflect a test year ending Dec. 31, 2007 (as opposed to the originally filed version based on a Sept. 30, 2007, test year). The revised case has not been officially certified by the ACC, but certification is expected by July 2. Unlike the company's last rate case, in which $315 million of the $322 million of rate relief granted was for fuel and power-related costs, the majority of the current case is for nonfuel expenditures.

While the revised case increased the company's request to $278 million (about an 8.5% increase, excluding the company's request that customers be assessed about $53 million in impact fees), the re-filing means that is unlikely the ACC will reach an outcome in the case before October 2009, and because the majority of APS' sales occur in the summer months, the company's financial performance could weaken in 2009.

This month, the company requested that the ACC allow it to continue to collect a $0.004/kWh charge that it has been collecting in 2007 to recover legacy purchased power and fuel deferrals. Given that the portion of deferred costs associated with this surcharge is due to be paid by July or August, APS has asked that the ACC continue the charge, but authorize collection as an interim base rate increase, subject to refund as part of the resolution of its rate case, expected in fall 2009. (Last year, the ACC approved similar relief for Tucson Electric Power in its pending rate case settlement when it granted the southern Arizona utility the opportunity to continue to collect charges related to a competitive transition charge, or CTC, while its rate case is pending.) While retail customers would essentially see no rate increase because APS is asking to continue the surcharge as an interim increase, it is unclear what action the ACC will take. A vote could occur as early as late summer.

In 2008, we expect a procedural schedule to be established for the APS rate case, and greater clarity around the timing of an outcome will be available once this is issued. Of note is that three of the five commissioners are facing term limits and will no longer be on the ACC beginning in 2009. Commissioners are popularly elected and about a dozen candidates have announced they will run for the November election. As a result, a majority of the commissioners presiding now will not be on the commission when an APS rate case ruling is rendered. What this means for credit quality is unclear.

APS was successful earlier this year in receiving approval for a change in its line extension policies, which eliminates the free footage allowance that used to be available for customers. As a result, the portion of the company's capital expenditures associated with new line extensions will be offset with contributions in aid of construction (CIAC). This is favorable and year to date ended March 31, 2008, had added about $10 million in incremental cash flows to the company. Because it is booked under investing activities, cash flow metrics are not improved, but we recognize the significant benefit of APS receiving upfront cash from customers to meet a portion of its distribution capital investment plans. Future cash flows from customers in the form of CIAC will depend on the number of new meter sets, which are significantly off year to date due to the poor real estate market in Arizona and a slowing economy generally.

APS has a well-diversified power supply portfolio that in 2007 consisted of about 22% nuclear generation, 37% coal generation, approximately 18% owned gas generation, and the balance, about 23%, of purchases. We would expect the company's purchased power obligations to steadily climb due to the fact that APS is under a self build moratorium until 2015. APS will also need to meet relatively stringent renewable portfolio standards (RPS). It has in place a surcharge to pass through to customers the costs of RPS compliance.

Palo Verde performance has stabilized, and it has a plan in place to address NRC concerns. As of the first quarter of 2008, the combined capacity factors for all three Palo Verde units was 93%, as compared with 79% for 2007 (which reflects in part an extended planned outage to replace steam generators at unit 3) and 71% in 2006, which largely reflects unplanned outages at unit 1 related to excessive vibration that occurred when that unit exited its extended outage for refueling and replacement of steam generators. Palo Verde Unit 3 remains in the NRC's "multiple/repetitive degraded cornerstone" column of the NRC's Action matrix, which subjects all three Palo Verde units to enhanced NRC inspection regime. Preliminary work in support of this took place throughout the summer of 2007. In February, the NRC issued its inspection report, which determined the plant was operating safely but which also outlined an improvement plan for APS. In late March, APS in turn submitted to the NRC a final improvement plant addressing issues raised in the NRC inspection report. While the nuclear units appear to be on a path to improve operational performance and restore NRC confidence in the operational and safety standards at the plant, this will remain an area of concern until the NRC removes it degraded designation.

Short-term credit factors

APS and PWCC's short-term rating is 'A-3'. Liquidity is adequate. Pinnacle West has $18 million of cash and cash equivalents, and total credit facilities of nearly $1.4 billion, with approximately $943 million available as of March 31, 2008. In October 2007, APS received approval from ACC to increase its authorized short-term debt borrowing capacity by $500 million, and long-term debt borrowing capacity by $1 billion. This will help address the needs of its growing customer base, and the increasing requirement for natural gas and purchased power.

Pinnacle West had close to $185 million available under its $300 million unsecured revolving credit facility that expires in December 2010. APS had $682 million available under its two unsecured revolving credit facilities, $400 million of which expires in December 2010, and $500 million in September 2011. SunCor has two credit facilities expiring in October and December 2008 that total $170 million and approximately $76 million, respectively, available as of September 2007.

Discretionary cash flow is expected to be negative for 2008 due to APS' capital expenditure plans. Excluding the remarketing of APS' pollution control debt, neither PWCC nor APS has any significant debt obligations maturing until 2011.

Outlook

The stable outlook reflects our expectation that consolidated cash flow volatility has been tamped down by the ACC's approval of a stronger PSA that speeds the recovery of fuel costs, but consolidated financial performance will continue to be challenged by regulatory lag at APS, which could be moderated by APS' pending interim rate request. The stable outlook is premised on no meaningful adverse changes in the company's business risks and continued financial performance that is not significantly weaker than 2007 results. Equity issuances will be expected to balance the capital structure of the company as APS continues to invest heavily in infrastructure. Ratings could be lowered to speculative grade if the company is not able to overcome the challenge of ensuring timely recovery of its prudently incurred costs through rate increases approved by the ACC. Given these challenges, and that presented by NRC scrutiny of Palo Verde, we see little potential for positive movement in the ratings or outlook.

ARIZONA CORPORATION COMMISSION
STAFF'S SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172 – INTERIM RATES
JULY 31, 2008

Staff Interim 2.22 Please provide the specific range of FFO/Debt ratio that each credit agency expects APS to maintain. Also, provide the supporting documents that APS relies upon for its answer to this request.

Response: Credit rating agencies do not have "expectations" of a company's credit metrics, but will assess that company's debt rating based on the financial metrics before them. See Attachment DEB-4 to the Testimony of Donald E. Brandt underlying the Company's general rate application and the attached APS13145 and APS13146 for each rating agency's description of its ratings criteria, as well as Mr. Brandt's summary of those criteria at pages 38-39 to that Testimony.

Witness: Donald Brandt

Moody's Investors Service

Global Credit Research
Credit Opinion
28 JUL 2008

EXHIBIT

ALL-STATE LEGAL®

Credit Opinion: Arizona Public Service Company

Arizona Public Service Company

Phoenix, Arizona, United States

Ratings

Category	**Moody's Rating**
Outlook	Stable
Issuer Rating	Baa2
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Subordinate Shelf	(P)Baa3
Commercial Paper	P-2
Parent: Pinnacle West Capital Corporation	
Outlook	Stable
Issuer Rating	Baa3
Sr Unsec Bank Credit Facility	Baa3
Senior Unsecured Shelf	(P)Baa3
Subordinate Shelf	(P)Ba1
Preferred Shelf	(P)Ba2
Commercial Paper	P-3

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Key Indicators

Arizona Public Service Company

ACTUALS	**1Q08 LTM**	**2007**	**2006**	**2005**
(CFO Pre-W/C + Interest) / Interest Expense [1][2]	**4.4x**	**4.2x**	**4.4x**	**3.6x**
(CFO Pre-W/C) / Debt [2]	**19.6%**	**18.3%**	**19.0%**	**14.5%**
(CFO Pre-W/C - Dividends) / Debt [2]	**14.1%**	**14.0%**	**14.5%**	**9.7%**
(CFO Pre-W/C - Dividends) / Capex [2]	**56.0%**	**58.7%**	**79.0%**	**53.1%**
Debt / Book Capitalization	**45.9%**	**45.9%**	**46.0%**	**47.5%**
EBITA Margin	**21.7%**	**22.6%**	**23.9%**	**20.9%**

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items [2] Changes in risk management and trading assets and liabilities are excluded from CFO Pre-W/C

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Corporate Profile

Arizona Public Service (APS: Baa2 senior unsecured, stable) is a vertically integrated electric utility that provides electric service to most of the state of Arizona with the major exceptions of about one-half of the Phoenix metropolitan area and the Tucson metropolitan area. APS is the primary subsidiary of Pinnacle West Capital Corporation (Pinnacle: Baa3 senior unsecured, stable), a holding company that through its other subsidiaries sells energy related products and services and develops residential and commercial real estate.

Recent Events

On July 25, 2008 Moody's revised the outlooks for APS and Pinnacle to stable from negative. The revision in outlook was a result of the companies' stable financial performance and also reflects our opinion of APS' improved prospects for more timely recovery of certain costs than had historically been the case. Our view is based on recent regulatory decisions involving recovery mechanisms for the cost of fuel and purchased power and transmission as well as recovery mechanisms for certain growth related costs. The outlook revision also recognized APS' demonstrated intent to attempt to minimize regulatory lag by filing for additional rate relief as soon as practicable.

Regulatory Activity

Approval of Line Extension Fees

In February 2008 the Arizona Corporation Commission (ACC) approved an amendment to APS' line extension schedule which eliminated certain free footage allowances and permitted APS to collect, on a current basis, costs relating to line extensions, which are estimated to be approximately $3,500 - $5,000 per new meter set (pre-tax). Moody's views the incremental (after-tax) cash flow resulting from these fees as recurring, and we have adjusted our credit metrics to reflect them as operating cash flows.

General Rate Case Filing

In June 2008, APS filed for a $278.2 million net rate increase (approximately 8.5% from existing customers) comprised of a $264.3 million non-fuel related increase and a $13.9 million net fuel-related increase. APS has proposed to collect up to $53 million of the increase specifically from new customers. The fuel increase request is net of approximately $170 million currently being collected in APS rates through its power supply adjustor (PSA) mechanism. APS' June filing is based on a test year ended December 2007. The request has been accepted by ACC Staff. A procedural schedule has been proposed with hearings in April 2009 and a decision expected in the latter part of 2009.

Request for Interim Increase

Also in June 2008, APS filed a request for an interim base rate increase of $.003987 per kWh to become effective upon the expiration of the $.003987 per kWh power supply adjustor surcharge currently in APS' rates. APS estimates the current surcharge will remain in effect through July. A procedural schedule has been set for this request, with hearings scheduled for September 2008 with a decision anticipated shortly thereafter.

Palo Verde

In February 2007, Nuclear Regulatory Commission (NRC) placed Palo Verde Unit 3 (PVU3), into the "multiple/repetitive degraded cornerstone" column of the NRC's action matrix, which has resulted in an enhanced inspection regimen and some increased operating costs for APS as it seeks to improve its processes at all three Palo Verde units. In February 2008, the NRC issued its revised confirmatory action letter, and as required, on March 31, 2008, APS submitted its revised improvement plan. The NRC will continue to provide increased oversight at Palo Verde until the facility has demonstrated sustained performance improvement. APS anticipates that this process will continue into 2009.

While operating performance at Palo Verde has improved, capacity factors continue to be impacted by planned outages (including a steam generator replacement in 2007) that have been extended by additional inspections. In 2007, the plant's average capacity factor was 79.0% versus 70.7% in 2006 and 77.4% in 2005. For the first quarter of 2008, the nuclear capacity factor was 93%.

Rating Rationale

The Baa2 rating for the senior unsecured obligations of APS reflects the stability of its regulated cash flows, the economic strength of its service territory, its regulatory environment, cash flow credit metrics that are appropriate

for the rating, and its position as a subsidiary of Pinnacle. The rating and outlook consider the traditionally challenging regulatory environment in Arizona, but also contemplates recent ACC decisions and regulatory activities that appear intended to reduce regulatory lag and provide more timely recovery of certain costs.

Given APS' current significant capital expenditure program, the company will require continued, timely regulatory support to maintain credit metrics that are appropriate for its rating. The stable outlook assumes APS will be reasonably successful in managing its regulatory relationships with an objective of achieving more timely recovery and an opportunity to earn a fair return. The rating also incorporates an expectation that APS will maintain a balanced approach with regards to financing its capital expenditures with a goal of maintaining or improving its current level of financial strength.

The most important drivers of the rating and outlook are as follows:

Regulatory Environment

Almost all of APS' operations are regulated which is generally viewed as positive for credit quality as regulated cash flows tend to be more stable and predictable than those of unregulated companies. This key factor is tempered somewhat by the historically challenging regulatory environment in Arizona, which Moody's ranks as below average for U.S. regulatory jurisdictions in terms of supportiveness or predictability and stability of regulated cash flows.

APS' operations are regulated by the ACC, an elected commission that has tended to render its decisions after prolonged consideration. Although regulatory lag remains a significant concern, recent decisions with regards to costs for fuel and purchased power and transmission, and certain growth related expenditures should reduce the time to recover some of these items.

General Regulatory Lag

APS' rate case activity is illustrative of an environment where there has tended to be below average assurance of timely recovery of costs and the ability to earn a reasonable return on investment. APS' 2003 rate case was not concluded until April 2005, and the increase received was less than half of the amount requested; the significant delay and relatively modest allowed increase resulted in the need for APS to quickly file another rate case in January 2006.

APS' January 2006 rate case was decided somewhat more quickly with a decision rendered in June 2007 wherein the utility received approximately three quarters of its requested increase; however, the allowed increase was almost entirely related to increased costs for fuel and purchased power. Of the $120 million requested for non-fuel items, only $7 million was approved. As a result, APS filed another general rate case as soon as practicable, based on a test year-ending September 2007. APS subsequently agreed with ACC Staff to re-file its rate increase request based on a test year-ending December 2007. Given the amount of time generally required to decide rate cases in Arizona, Moody's estimates that new rates will not be implemented until the latter part of 2009.

Reduced Regulatory Lag for Certain Items

The ACC's June 2007 decision included a significantly improved mechanism for the recovery of fuel and purchased power costs, incorporating a forward estimate of fuel costs in addition to the continued recovery of past deferrals. Fuel and purchased power costs have been among APS' most volatile operating expenses and Moody's views the ACC's recent approach to this problem as supportive of the utility's credit profile. However, we note that APS fuel recovery factor remains subject to an annual cap, potentially delaying recoveries beyond a one-year true-up period, and subject to a 90/10 sharing mechanism wherein 10% of costs are not able to be recovered.

In June 2008, APS requested an interim base rate increase that would take effect upon expiration in July 2008 of a surcharge being collected under the fuel clause adjustment mechanism. The request could potentially allow base rate cost recovery, subject to refund, prior to the completion of the next general rate case. This could result in a measure of rate stability as there could potentially be no immediate incremental increase to customers, and there would likely ultimately be a smaller base rate increase. Since the ACC and interested parties needed more time to consider this request, a decision is now expected late September to mid October. If implemented new rates could be in place November 1 when lower winter rates go into effect, thereby allowing some degree of rate stability. Moody's notes that the ACC has granted interim increases in the recent past. Moody's views mechanisms designed to reduce the time required to recover a utility's costs, such as the requested interim base rate increase a positive for credit quality.

In its June 2007 order, the ACC requested that APS propose mechanisms that could potentially allow growth to

pay for itself, rather than being paid by the current customer base. In February 2008, the ACC approved an amendment to APS' line extension schedule that should provide an almost immediate recovery of the cost of certain growth related capital investment reducing the amount of external financing needed to support these expenditures. Moody's views this revision as positive for credit, virtually eliminating the normal regulatory lag that would otherwise be associated with seeking recovery of these expenditures.

In its 2005 order, the ACC authorized a transmission tracking adjustment (TCA) mechanism designed to allow retail transmission charges to track those authorized by the FERC. The TCA was initially implemented in March 2008, and timely adjusted following an automatic adjustment in FERC transmission rates in June 2008.

Service Territory Growth Slowing

Growth in APS' service territory has slowed significantly below the 4-5% level experienced in 2005 and 2006. In 2007, customer growth was approximately 3%; for the first quarter of 2008 customer growth slowed to 2% and is not expected to return to historical heights over the near-to-medium term. Although, a growing customer base can provide a source of increased revenue, assuming timely recovery of increased growth related investment and increased costs for fuel and purchased power, it also has resulted in a continuing need for capital investment and regulatory relief. The stable outlook assumes APS will continue to take a balanced approach with regards to the funding of its capital expenditures. Moody's also believes a sustained period of slower growth could potentially temper APS need for capital investment which could reduce its financing requirements.

Financial Metrics

In 2004 and 2005, APS' key financial metrics reflected the fact that it had been unable to recover fully increased costs for fuel, purchased power and capital spending on a timely basis. For example, the ratio of cash from operations prior to changes in current assets and liabilities (CFO pre-WC) / debt (incorporating Moody's standard analytic adjustments) dropped into the mid-teens. Financial metrics improved in 2006 and 2007 with CFO pre - WC / debt moving to the upper-teens as fuel recovery improved. These metrics are now toward the middle-to-upper end of the 13% to 25% range identified in Moody's Rating Methodology for Global Electric Utilities for Baa rated entities on a stand-alone basis within the medium risk category. Cash flow credit metrics are expected to remain in that range over the near-to-medium term reflecting more timely cost recovery of certain items and assuming capital expenditures are financed in a manner that is also supportive of APS current financial strength and flexibility. In general, Moody's would look for APS to have financial metrics that are somewhat stronger than comparably rated utility operating companies that operate in regulatory environments that have historically been more supportive of credit quality.

Subsidiary of Pinnacle West

Pinnacle, APS' parent company, conducts a modest amount of non-regulated activities including power marketing and trading, sales of energy related products and services, and residential and commercial real estate development through subsidiaries including SunCor Development Company (real estate). However, for the past several years almost all of Pinnacle's cash from operations has been generated by APS. Over the near-to-medium term, Pinnacle's non-regulated businesses, are not expected to meaningfully contribute to, or detract from, consolidated cash flows. Although residential real estate sales slowed considerably in 2006, 2007 and continuing into 2008, Pinnacle's joint venture strategy with other developers, combined with its successfully completed asset sales program (implemented 2003-2005) has significantly reduced its exposure to this volatile sector. The parent company also maintains a modest amount of leverage with holding company debt at less than 10% of consolidated debt.

Liquidity Profile

APS' Prime-2 short-term rating for commercial paper reflects the relatively stable and predictable cash flow provided by its regulated electric utility operations.

For the year ended December 2007, APS' cash flow from operations of approximately $765 million covered approximately 72% of its outlays, including capital expenditures of approximately $900 million and dividends to Pinnacle of $170 million. The shortfall was funded via a combination of internal and external sources of cash including $218 million of short term debt proceeds, approximately $40 million of equity contributions from Pinnacle and cash on hand.

For the next several years, APS' capital expenditures are expected to be in the range of $1.0 billion per year, primarily to expand APS' transmission and distribution network to meet growing customer needs, but also to upgrade its existing utility properties and for other environmental purposes. Funding for these increased capital

expenditures is expected to be provided via a combination of internal and external sources of cash, including operating cash flow, equity contributions from Pinnacle and long and short term debt financing.

Over the last several years, APS has paid dividends to Pinnacle of $170 million per year. Moody's expects APS' dividends are likely to remain near this level in 2008 and over the medium term.

APS' pattern of cash flow is seasonal as the peak of electric demand occurs during the summer months due to high air conditioning load that exists in its service territory. As a result, the bulk of its commercial paper borrowings typically occur in the second and third quarters of each year. As of March 31, 2008, APS had $90 million of commercial paper and $100 of short-term debt outstanding under its revolving credit facility.

APS has historically maintained a very modest level of cash on its balance sheet; as of March 31, 2008, APS had reported cash and cash equivalents of approximately $8 million.

APS' commercial paper program is sized at $250 million and is currently supported by two committed lines of credit totaling $900 million, a $400 million line that expires in December 2010 and a $500 million line that expires in September 2011. As of March 31, 2008, APS had approximately $100 million of borrowings under its credit facilities. Overall availability under these credit facilities was $796 million, of which $90 million was back-stopping commercial paper outstanding. Both credit agreements have one financial covenant that requires the ratio of debt to total capitalization not to exceed 65%. As of March 31, 2008, APS' debt to total capitalization ratio, calculated in accordance with the credit documents, was approximately 47%. The credit agreements do not require a Material Adverse Change (MAC) representation for revolver borrowings. No rating triggers exist in any APS credit facilities though interest costs may increase under various financing agreements if a downgrade occurs. APS nearest long term debt maturity is $400 million of unsecured notes due in 2011. In 2010, APS must replace letters of credit supporting approximately $200 million of variable rate pollution control bonds.

APS' Prime-2 rating for its short term obligations assumes that the company will manage the amount of commercial paper and other near term obligations outstanding within the limits of its readily available sources of cash, including its committed bank credit facilities.

Rating Outlook

The stable outlook reflects the nature of APS' predominately regulated cash flows and Moody's view that its improved cash flow financial metrics are likely to be sustainable. The outlook assumes APS' will be reasonably successful in managing its regulatory relationships and that capital expenditures will be financed in a balanced manner with a goal of maintaining or improving APS current position of financial strength.

What Could Change the Rating - Up

APS' rating is not likely to be revised upward in the near-to-medium term. Longer term, if there is an increase in supportive regulatory treatment resulting in material, timely rate increases, or if there are material reductions in costs or leverage such that Moody's could anticipate key financial ratios improving significantly from their current levels, if for example, a ratio of CFO pre -WC / debt could be maintained in the mid twenty percent range.

What Could Change the Rating - Down

A downgrade could result if Palo Verde experiences an extended outage and APS is unable to recover, in a timely manner, higher maintenance and purchased power costs, or if APS' regulatory lag for capital spending becomes more pronounced. A downgrade could result if Moody's expects a sustained weakening of financial metrics, if for example, the ratio of CFO pre -WC / debt would remain in the mid-teens for an extended period.

Rating Factors

Arizona Public Service Company

62000

Select Key Ratios for Global Regulated Electric Utilities

Rating	Aa	Aa	A	A	Baa	Baa	Ba	Ba
Level of Business Risk	Medium	Low	Medium	Low	Medium	Low	Medium	Low

CFO pre-W/C to Interest (x) [1]	>6	>5	3.5-6.0	3.0-5.7	2.7-5.0	2-4.0	<2.5	<2
CFO pre-W/C to Debt (%) [1]	>30	>22	22-30	12-22	13-25	5-13	<13	<5
CFO pre-W/C - Dividends to Debt (%) [1]	>25	>20	13-25	9-20	8-20	3-10	<10	<3
Total Debt to Book Capitalization (%)	<40	<50	40-60	50-70	50-70	60-75	>60	>70

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

June 25, 2008

Summary:
Arizona Public Service Co.

Primary Credit Analyst:
Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

Table Of Contents

Summary:

Arizona Public Service Co.

Credit Rating: BBB-/Stable/A-3

Rationale

Standard & Poor's Ratings Services today affirmed the 'BBB-' corporate credit rating assigned to Pinnacle West Capital Corporation (PWCC) and its utility, Arizona Public Service. The outlook is stable. The consolidated credit ratings of PWCC primarily reflect the operations of its largest subsidiary, APS, a regulated, electric utility serving about 1.1 million customers within its service territory, which spans roughly two-thirds of Arizona and includes about half of the Phoenix MSA. We view the business profile of PWCC and APS to be 'strong'. While the company continues to benefit from a number of favorable attributes including a good service territory, a reasonably balanced power supply portfolio and a good PSA. However, APS' continues to face significant regulatory challenges.

APS provided the company with about 92% of its consolidated net income in 2007. SunCor, PWCC's real estate development company, provided about 4%, but due to the significant real estate slowdown in the southwest, it is unlikely it will be a meaningful contributor of cash flows or income over the next several years. (Prior to the real estate downturn, our forecasts have conservatively limited earnings from this subsidiary due to the cyclic nature of its cash flows.) Other subsidiary operations include Pinnacle West Trading and Marketing, which contributed about 4% of consolidated net income in 2007. This subsidiary has since last year been minimizing trading operations. Its largest contract was serving all-requirements load for UNS Electric Inc., which ended in May 2008.

We view the financial profile of PWCC and APS to be 'aggressive', which reflects: year-end debt to total capitalization of 57% (adjusted for items such as power purchases and operating leases); heavy capital spending that is expected to drive negative free operating cash flow for the foreseeable future; cash flow weakness as a function of protracted rate cases; and, while modest, the presence of unregulated activities, which can be unpredictable in their earnings contributions.

Because the preponderance of cash flows for consolidated operations stems from APS, we expect financial performance will continue to be heavily dependent on regulatory outcomes. The conclusion of APS' last general rate case in June 2007 (filed in November 2005 and revised in early 2006) provided the company with mechanisms to recover legacy deferrals and speed the recovery of fuel costs going forward. This rate relief, in place for the last half of 2007, assisted the company in maintaining credit metrics roughly in line with past performance. Funds from operations (FFO) to total debt was about 16% at year-end, with FFO interest coverage around 4x. On a trailing 12-month basis the company's performance has been slightly above these levels, due in part to the federal tax stimulus package approved by the U.S. Congress earlier this year, which is expected to increase deferred taxes (which are added back to FFO and thus increase this total).

We expect APS to be in more or less continuous rate case mode for the next few years. Given APS' capital spending program, forecasted to be about $1.1 billion annually through 2010, the utility will need to file regular general rate cases to manage recovery of its investment. The use of a historical test year in Arizona, coupled with the fact that fully litigated rate cases take between 18 to 24 months to complete, is expected to result in no meaningful improvement in financial performance through 2009 and possibly beyond, depending on the timing and the

outcome of the company's current case.

APS filed its current rate case in March 2008. ACC staff requested that the company revise its filing to reflect a test year ending Dec. 31, 2007 (as opposed to the originally filed version based on a Sept. 30, 2007, test year). The revised case has not been officially certified by the ACC, but certification is expected by July 2. Unlike the company's last rate case, in which $315 million of the $322 million of rate relief granted was for fuel and power-related costs, the majority of the current case is for nonfuel expenditures.

While the revised case increased the company's request to $278 million (about an 8.5% increase, excluding the company's request that customers be assessed about $53 million in impact fees), the re-filing means that is unlikely the ACC will reach an outcome in the case before October 2009, and because the majority of APS' sales occur in the summer months, the company's financial performance could weaken in 2009.

This month, the company requested that the ACC allow it to continue to collect a $0.004/kWh charge that it has been collecting in 2007 to recover legacy purchased power and fuel deferrals. Given that the portion of deferred costs associated with this surcharge is due to be paid by July or August, APS has asked that the ACC continue the charge, but authorize collection as an interim base rate increase, subject to refund as part of the resolution of its rate case, expected in fall 2009. (Last year, the ACC approved similar relief for Tucson Electric Power in its pending rate case settlement when it granted the southern Arizona utility the opportunity to continue to collect charges related to a competitive transition charge, or CTC, while its rate case is pending.) While retail customers would essentially see no rate increase because APS is asking to continue the surcharge as an interim increase, it is unclear what action the ACC will take. A vote could occur as early as late summer.

In 2008, we expect a procedural schedule to be established for the APS rate case, and greater clarity around the timing of an outcome will be available once this is issued. Of note is that three of the five commissioners are facing term limits and will no longer be on the ACC beginning in 2009. Commissioners are popularly elected and about a dozen candidates have announced they will run for the November election. As a result, a majority of the commissioners presiding now will not be on the commission when an APS rate case ruling is rendered. What this means for credit quality is unclear.

APS was successful earlier this year in receiving approval for a change in its line extension policies, which eliminates the free footage allowance that used to be available for customers. As a result, the portion of the company's capital expenditures associated with new line extensions will be offset with contributions in aid of construction (CIAC). This is favorable and year to date ended March 31, 2008, had added about $10 million in incremental cash flows to the company. Because it is booked under investing activities, cash flow metrics are not improved, but we recognize the significant benefit of APS receiving upfront cash from customers to meet a portion of its distribution capital investment plans. Future cash flows from customers in the form of CIAC will depend on the number of new meter sets, which are significantly off year to date due to the poor real estate market in Arizona and a slowing economy generally.

APS has a well-diversified power supply portfolio that in 2007 consisted of about 22% nuclear generation, 37% coal generation, approximately 18% owned gas generation, and the balance, about 23%, of purchases. We would expect the company's purchased power obligations to steadily climb due to the fact that APS is under a self build moratorium until 2015. APS will also need to meet relatively stringent renewable portfolio standards (RPS). It has in place a surcharge to pass through to customers the costs of RPS compliance.

Palo Verde performance has stabilized, and it has a plan in place to address NRC concerns. As of the first quarter of 2008, the combined capacity factors for all three Palo Verde units was 93%, as compared with 79% for 2007 (which reflects in part an extended planned outage to replace steam generators at unit 3) and 71% in 2006, which largely reflects unplanned outages at unit 1 related to excessive vibration that occurred when that unit exited its extended outage for refueling and replacement of steam generators. Palo Verde Unit 3 remains in the NRC's "multiple/repetitive degraded cornerstone" column of the NRC's Action matrix, which subjects all three Palo Verde units to enhanced NRC inspection regime. Preliminary work in support of this took place throughout the summer of 2007. In February, the NRC issued its inspection report, which determined the plant was operating safely but which also outlined an improvement plan for APS. In late March, APS in turn submitted to the NRC a final improvement plant addressing issues raised in the NRC inspection report. While the nuclear units appear to be on a path to improve operational performance and restore NRC confidence in the operational and safety standards at the plant, this will remain an area of concern until the NRC removes it degraded designation.

Short-term credit factors

APS and PWCC's short-term rating is 'A-3'. Liquidity is adequate. Pinnacle West has $18 million of cash and cash equivalents, and total credit facilities of nearly $1.4 billion, with approximately $943 million available as of March 31, 2008. In October 2007, APS received approval from ACC to increase its authorized short-term debt borrowing capacity by $500 million, and long-term debt borrowing capacity by $1 billion. This will help address the needs of its growing customer base, and the increasing requirement for natural gas and purchased power.

Pinnacle West had close to $185 million available under its $300 million unsecured revolving credit facility that expires in December 2010. APS had $682 million available under its two unsecured revolving credit facilities, $400 million of which expires in December 2010, and $500 million in September 2011. SunCor has two credit facilities expiring in October and December 2008 that total $170 million and approximately $76 million, respectively, available as of September 2007.

Discretionary cash flow is expected to be negative for 2008 due to APS' capital expenditure plans. Excluding the remarketing of APS' pollution control debt, neither PWCC nor APS has any significant debt obligations maturing until 2011.

Outlook

The stable outlook reflects our expectation that consolidated cash flow volatility has been tamped down by the ACC's approval of a stronger PSA that speeds the recovery of fuel costs, but consolidated financial performance will continue to be challenged by regulatory lag at APS, which could be moderated by APS' pending interim rate request. The stable outlook is premised on no meaningful adverse changes in the company's business risks and continued financial performance that is not significantly weaker than 2007 results. Equity issuances will be expected to balance the capital structure of the company as APS continues to invest heavily in infrastructure. Ratings could be lowered to speculative grade if the company is not able to overcome the challenge of ensuring timely recovery of its prudently incurred costs through rate increases approved by the ACC. Given these challenges, and that presented by NRC scrutiny of Palo Verde, we see little potential for positive movement in the ratings or outlook.

The McGraw-Hill Companies

ORIGINAL

APS

A subsidiary of Pinnacle West Capital Corporation

Barbara Klemstine
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Regulation and Pricing

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EXHIBIT
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June 29, 2007

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: APS Cash Position and Financial Ratios Compliance Filing (for April 30, 2007)
DOCKET NO. E-01345A-06-0009
DECISION NO. 68685

Dear Madam or Sir:

Attached is the monthly report on Arizona Public Service Company and Pinnacle West Capital Corporations cash position and financial ratios, as required by Decision No. 68685.

If you or your staff have any questions, please call Jeff Johnson at 602-250-2661.

Sincerely,

Barbara Klemstine

Barbara Klemstine

BAK/bgs

cc: Ernest Johnson
Brian Bozzo

Arizona Corporation Commission
DOCKETED

JUN 29 2007

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Monthly Cash Position and Financial Ratio Report (1)

		April 30, 2007
Ending cash and invested position (in millions):		
APS	$	76
PNW	$	95
APS Financial ratios (12 months ending):		
Funds from operations to debt		19.9%
Debt to capital		54.4%
Funds from operations interest coverage		4.0x
Projected APS funds from operations (in millions):		
12 months ending 12/31/07	$	742

(1) Required by Decision No. 68685 until resolution of general rate case

APS ORIGINAL A subsidiary of Pinnacle West Capital Corporation

50

Barbara Klemstine
Director
Regulation and Pricing

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e-mail Barbara.Klemstine@aps.com

Mail Station 9708
PO Box 53999
Phoenix, Arizona 85072-3999

May 31, 2007

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: APS Cash Position and Financial Ratios Compliance Filing (for March 30, 2007)
DOCKET NO. E-01345A-06-0009
DECISION NO. 68685

Dear Madam or Sir:

Attached is the monthly report on Arizona Public Service Company and Pinnacle West Capital Corporations cash position and financial ratios, as required by Decision No. 68685.

If you or your staff have any questions, please call Jeff Johnson at 602-250-2661.

Sincerely,

Barbara Klemstine

Barbara Klemstine

BAK/bgs

cc: Ernest Johnson
Brian Bozzo

Monthly Cash Position and Financial Ratio Report (1)

		March 31, 2007
Ending cash and invested position (in millions):		
APS	$	103
PNW	$	121
APS Financial ratios (12 months ending):		
Funds from operations to debt		19.3%
Debt to capital		54.2%
Funds from operations interest coverage		4.0x
Projected APS funds from operations (in millions):		
12 months ending 12/31/07	$	742

(1) Required by decision no. 68685 until resolution of general rate case

APS

A subsidiary of Pinnacle West Capital Corporation

Barbara Klemstine
Director
Regulation and Pricing

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Mail Station 9708
PO Box 53999
Phoenix, Arizona 85072-3999

April 30, 2007

Ernest Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: APS Cash Position and Financial Ratios Compliance Filing (for February 28, 2007)
DECISION NO. 68685
DOCKET NO. E-01345A-06-0009

Dear Mr. Johnson:

Pursuant to Decision No. 68685, Arizona Public Service Company and Pinnacle West Capital Corporation are required to file a monthly report on their cash position and financial ratios.

The attached information is confidential as financial data for APS and PWCC has not yet been released in SEC 10-Q filings for the first quarter of 2007, and is being provided pursuant to an executed confidentiality agreement.

If you have any questions, please call Jeff Johnson at 602-250-2661.

Sincerely,

Barbara Klemstine/sc

Barbara Klemstine

BK/dst

Monthly Cash Position and Financial Ratio Report (1)

		February 28, 2007
Ending cash and invested position (in millions):		
APS	$	143
PNW	$	160
APS Financial ratios (12 months ending):		
Funds from operations to debt		19.0%
Debt to capital		54.3%
Funds from operations interest coverage		3.9x
Projected APS funds from operations (in millions):		
12 months ending 12/31/07	$	742

(1) Required by decision no. 68685 until resolution of general rate case

APS

A subsidiary of Pinnacle West Capital Corporation

Barbara Klemstine
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Phoenix, Arizona 85072-3999

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AZ CORP COMM
Director Utilities

March 30, 2007

Ernest Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: APS Cash Position and Financial Ratios Compliance Filing (for January 31, 2007)
DECISION NO. 68685
DOCKET NO. E-01345A-06-0009

Dear Mr. Johnson:

Pursuant to Decision No. 68685, Arizona Public Service Company and Pinnacle West Capital Corporation are required to file a monthly report on their cash position and financial ratios.

The attached Information is confidential as financial data for APS and PWCC has not yet been released in SEC 10-Q filings for the first quarter of 2007, and is being provided pursuant to an executed confidentiality agreement.

If you have any questions, please call Jeff Johnson at 602-250-2661.

Sincerely,

Barbara Klemstine

BK/dst

cc: Brian Bozzo

Monthly Cash Position and Financial Ratio Report

		January 31, 2007
Ending cash and invested position (in millions):		
APS	$	122
PNW	$	152
APS Financial ratios (12 months ending):		
Funds from operations to debt		18.3%
Debt to capital		54.2%
Funds from operations interest coverage		3.8x
Projected APS funds from operations (in millions):		
12 months ending 12/31/07	$	742

ORIGINAL

APS

A subsidiary of Pinnacle West Capital Corporation

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PO Box 53999
Phoenix, Arizona 85072-3999

March 1, 2007

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: APS Cash Position and Financial Ratios Compliance Filing (for December 31, 2006)
DOCKET NO. E-01345A-06-0009 DECISION NO. 68685

Dear Madam or Sir:

Pursuant to Decision No. 68685, attached is Arizona Public Service Company's and Pinnacle West Capital Corporation's monthly report on their cash position and financial ratios.

If you have any questions, please call me.

Sincerely,

Barbara Klemstine

Barbara Klemstine

BK/dst

CC: Ernest Johnson
Brian Bozzo

Arizona Corporation Commission
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Monthly Cash Position and Financial Ratio Report (1)

		December 31, 2006
Ending cash and invested position (in millions):		
APS	$	115
PNW	$	120
APS Financial ratios (12 months ending):		
Funds from operations to debt		18.3%
Debt to capital		54.2%
Funds from operations interest coverage		3.8x
Projected APS funds from operations (in millions):		
12 months ending 12/31/07	$	742

(1) Required by decision no. 68685 until resolution of general rate case

A subsidiary of Pinnacle West Capital Corporation

Barbara Klemstine
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January 31, 2007

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Dire

Ernest Johnson
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: APS Cash Position and Financial Ratios Compliance Filing (for November 30, 2006)
DOCKET NO. E-01345A-06-0009 DECISION NO. 68685

Dear Sir:

Pursuant to Decision No. 68685, Arizona Public Service Company and Pinnacle West Capital Corporations are to make monthly reports on their cash position and financial ratios.

This attachment is confidential and is being provided pursuant to the protective agreement.

If you have any questions, please call me.

Sincerely,

Barbara Klemstine

BK/dst

CONFIDENTIAL

Monthly Cash Position and Financial Ratio Report (1)

		November 30, 2006
Ending cash and invested position (in millions):		
APS	$	341
PNW	$	358
APS Financial ratios (12 months ending):		
Funds from operations to debt		18.0%
Debt to capital		53.1%
Funds from operations interest coverage		3.9x
Projected APS funds from operations (in millions):		
12 months ending 12/31/06	$	647

(1) Required by decision no. 68685 until resolution of general rate case

ORIGINAL

APS

A subsidiary of Pinnacle West Capital Corporation

RECEIVED

Brian Brumfield
Supervisor
Regulatory Affairs

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2006 DEC 21 P 4: 44

AZ CORP COMMISSION
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December 21, 2006

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: APS Cash Position and Financial Ratios Compliance Filing
DOCKET NO. E-01345A-06-0009 DECISION NO. 68685

Dear Madam or Sir:

Attached is the monthly report on Arizona Public Service Company and Pinnacle West Capital Corporations cash position and financial ratios, as required by Decision No. 68685.

If you or your staff have any questions, please feel free to call me.

Sincerely,

Brian Brumfield
Supervisor
Regulatory Affairs

BB/vld

CC: Ernest Johnson
Brian Bozzo (without attachments)

Arizona Corporation Commission
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Monthly Cash Position and Financial Ratio Report (1)

		October 31, 2006
Ending cash and invested position (in millions):		
APS	$	397
PNW	$	407
APS Financial ratios (12 months ending):		
Funds from operations to debt		17.8%
Debt to capital		53.8%
Funds from operations interest coverage		4.0x
Projected APS funds from operations (in millions):		
12 months ending 12/31/06	$	647

(1) Required by decision no. 68685 until resolution of general rate case

ORIGINAL

APS

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2006 NOV 30 P 4: 27

AZ CORP COMMISSION
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November 30, 2006

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: APS Cash Position and Financial Ratios Compliance Filing
DOCKET NO. E-01345A-06-0009 DECISION NO. 68685

Dear Madam or Sir:

Attached is the monthly report on Arizona Public Service Company and Pinnacle West Capital Corporations cash position and financial ratios, as required by Decision No. 68685.

If you or your staff have any questions, please feel free to call me.

Sincerely,

Brian Brumfield /CJ

Brian Brumfield
Supervisor
Regulatory Affairs

BB/vld

CC: Ernest Johnson
Brian Bozzo (without attachments)

Arizona Corporation Commission
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Monthly Cash Position and Financial Ratio Report (1)

		September 30, 2006
Ending cash and invested position (in millions):		
APS	$	321
PNW	$	332
APS Financial ratios (12 months ending):		
Funds from operations to debt		17.3%
Debt to capital		53.7%
Funds from operations interest coverage		3.9x
Projected APS funds from operations (in millions):		
12 months ending 12/31/06	$	647

(1) Required by decision no. 68685 until resolution of general rate case

APS

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October 31, 2006

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AZ CORP COMM
Director Utilities

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: APS Cash Position and Financial Ratios Compliance Filing
DOCKET NO. E-01345A-06-0009 DECISION NO. 68685

Dear Madam or Sir:

Attached is the monthly report on Arizona Public Service Company and Pinnacle West Capital Corporations cash position and financial ratios, as required by Decision No. 68685.

Portions of this filing are confidential and therefore will not be docketed

If you or your staff have any questions, please feel free to call me

Sincerely,

Brian Brumfield

Brian Brumfield
Supervisor
Regulatory Affairs

BB/vld

CC: Ernest Johnson
Brian Bozzo

Monthly Cash Position and Financial Ratio Report (1)

CONFIDENTIAL

		August 31, 2006
Ending cash and invested position (in millions):		
APS	$	459
PNW	$	526
APS Financial ratios (12 months ending):		
Funds from operations to debt		17.7%
Debt to capital		53.8%
Funds from operations interest coverage		4.0x
Projected APS funds from operations (in millions):		
12 months ending 12/31/06	$	647

(1) Required by decision no. 68685 until resolution of general rate case

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2006 SEP 29 P 4: 31
AZ CORP COMMISSION
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September 29, 2006

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SEP 29 2006
AZ CORP COMM
Director Utilities

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: APS Cash Position and Financial Ratios Compliance Filing
DOCKET NO. E-01345A-06-0009 DECISION NO. 68685

Dear Madam or Sir:

Attached is the monthly report on Arizona Public Service Company and Pinnacle West Capital Corporations cash position and financial ratios, as required by Decision No. 68685.

Portions of this filing are confidential and therefore will not be docketed.

If you or your staff have any questions, please feel free to call me.

Sincerely,

Brian Brumfield
Supervisor
Regulatory Affairs

BB/vld

CC: Ernest Johnson
Brian Bozzo

CONFIDENTIAL

Monthly Cash Position and Financial Ratio Report (1)

		July 31, 2006
Ending cash position (in millions):		
APS	$	10
PNW	$	86
APS Financial ratios (12 months ending):		
Funds from operations to debt		17.5%
Debt to capital		54.0%
Funds from operations interest coverage		4.1x
Projected APS funds from operations (in millions):		
12 months ending 12/31/06	$	647

(1) Required by decision no. 68685 until resolution of general rate case

ORIGINAL

APS

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Mail Station 9708
PO Box 53999
Phoenix, Arizona 85072-3999

August 30, 2006

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: DOCKET NO. E-01345A-06-0009
DECISION NO. 68685

Dear Madam or Sir:

Attached is the monthly report on Arizona Public Service Company and Pinnacle West Capital Corporations cash position and financial ratios, as required by Decision No. 68685.

If you or your staff have any questions, please feel free to call me.

Sincerely,

Brian Brumfield
Supervisor
Regulatory Affairs

BB/vld

CC: Ernest Johnson
Brian Bozzo

Arizona Corporation Commission
DOCKETED
AUG 30 2006

DOCKETED BY	

RECEIVED
2006 AUG 30 P 4: 23
AZ CORP COMMISSION
DOCUMENT CONTROL

Monthly Cash Position and Financial Ratio Report (1)

		June 30, 2006
Ending cash position (in millions):		
APS	$	-
PNW	$	16
APS Financial ratios (12 months ending):		
Funds from operations to debt		16.2%
Debt to capital		52.0%
Funds from operations interest coverage		3.4x
Projected APS funds from operations (in millions):		
12 months ending 12/31/06	$	585

(1) Required by decision no. 68685 until resolution of general rate case

APS

A subsidiary of Pinnacle West Capital Corporation

Brian Brumfield
Supervisor
Regulation, Pricing & Administration

Tel. 602-250-2708
Fax 602-250-3003
e-mail Brian.Brumfield@aps.com

Mail Station 9708
PO Box 53999
Phoenix, Arizona 85072-3999

RECEIVED
JUL 27 2006
AZ CORP COMM
Director Utilities

RECEIVED
JUL 27 2006
LEGAL DIV
ARIZ. CORPORATION COMMISSION

July 27, 2006

Mr. Ernest Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: DOCKET NO. E-01345A-05-0009
DECISION NO. 68685

Attached is the monthly report for Arizona Public Service Company and Pinnacle West Capital Corporation's cash position and financial ratios, as required by Decision No. 68685.

Portions of this filing are confidential and therefore will not be docketed.

If you or your staff have any questions, please feel free to call me.

Sincerely,

Brian Brumfield
Supervisor
Regulation, Pricing and Administration

BB/vld

Attachment

CC: Brian Bozzo
Docket Control

RECEIVED
2006 JUL 27 P 4:51
AZ CORP COMMISSION
DOCUMENT CONTROL

Monthly Cash Position and Financial Ratio Report (1)

		May 31, 2006
Ending cash position (in millions):		
APS	$	-
PNW	$	47
APS Financial ratios (12 months ending):		
Funds from operations to debt		15.1%
Debt to capital		51.7%
Funds from operations interest coverage		3 4x
Projected APS funds from operations (in millions):		
12 months ending 12/31/06	$	585

(1) Required by decision no. 68685 until resolution of general rate case

APS

A subsidiary of Pinnacle West Capital Corporation

Brian Brumfield
Supervisor
Regulation, Pricing & Administration

Tel. 602-250-2708
Fax 602-250-3003
e-mail Brian.Brumfield@aps.com

Mail Station 9708
PO Box 53999
Phoenix, Arizona 85072-3999

June 28, 2006

Mr. Ernest Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: DOCKET NO. E-01345A-06-0009
DECISION NO. 68685

Attached is the monthly report for Arizona Public Service Company and Pinnacle West Capital Corporation's cash position and financial ratios, as required by Decision No. 68685.

Portions of this filing are confidential and therefore will not be docketed.

If you or your staff have any questions, please feel free to call me.

Sincerely,

Brian Brumfield
Supervisor
Regulation, Pricing and Administration

BB/vld

Attachment

CC: Brian Bozzo
Docket Control

RECEIVED
JUN 2 8 2006
AZ CORP COMM
Director Utilities

RECEIVED
2006 JUN 28 P 4: 51
AZ CORP COMMISSION
DOCUMENT CONTROL

Monthly Cash Position and Financial Ratio Report (1)

		March 31, 2006		April 30, 2006
Ending cash position (in millions):				
APS	$	77	$	-
PNW	$	315	$	90
APS Financial ratios (12 months ending):				
Funds from operations to debt		14.3%		14.2%
Debt to capital		50.5%		50.5%
Funds from operations interest coverage		3.2x		3.2x
Projected APS funds from operations (in millions):				
12 months ending 12/31/06	$	585	$	585

(1) Required by decision no. 68685 until resolution of general rate case

ORIGINAL

APS

A subsidiary of Pinnacle West Capital Corporation

50

Brian Brumfield
Supervisor
Regulation, Pricing & Administration

Tel. 602-250-2708
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Mail Station 9708
PO Box 53999
Phoenix, Arizona 85072-3999

June 2, 2006

Docket Control
Arizona Corporation Commission
1200 W. Washington
Phoenix, Arizona 85007

RE: DOCKET NO. E-01345A-06-0009
DECISION NO. 68685

Dear Madam or Sir:

Attached is the monthly report on Arizona Public Service Company and Pinnacle West Capital Corporations cash position and financial ratios, as required by Decision No. 68685.

If you or your staff have any questions, please feel free to call me.

Sincerely,

Brian Brumfield
Supervisor
Regulation, Pricing and Administration

BB/bec

Cc: Brian Bozzo
Ernest Johnson

RECEIVED
2006 JUN -2 P 4:45
AZ CORP COMMISSION
DOCUMENT CONTROL

Monthly Cash Position and Financial Ratio Report (1)

		March 31, 2006
Ending cash position (in millions):		
APS	$	77
PNW	$	315
APS Financial ratios (12 months ending):		
Funds from operations to debt		14.3%
Debt to capital		50.5%
Funds from operations interest coverage		3.2x
Projected APS funds from operations (in millions):		
12 months ending 12/31/06	$	585

(1) Required by Decision No. 68685 until resolution of general rate case

EXHIBIT

ALL-STATE LEGAL®

S-7

APS

David Rumolo
Manager
Regulation & Pricing

Tel. 602-250-3933
Fax 602-250-3003
e-mail David.Rumolo@aps.com

Mail Station 9708
PO Box 53999
Phoenix, Arizona 85072-3999

September 12, 2008

Maureen A. Scott
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

RE: STAFF'S TENTH SET OF DATA REQUESTS IN THE 2008 INTERIM RATE CASE MATTER
DOCKET NO. E-01345A-08-0172

Dear Ms. Scott,

Enclosed is Arizona Public Service Company's ("APS's") supplemental response to Staff's Tenth Set of Data Requests regarding the interim rate case, specifically Staff 10.3 (h) and Staff 10.3 (i).

If you or your staff have any questions regarding the enclosed information, please contact me at (602) 250-3933.

Sincerely,

David Rumolo

Attachments

DR/dk

CC: Connie Fitzsimmons
Ralph Smith
Parties of Record

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
SEPTEMBER 9, 2008

Staff Interim 10.3 Refer to Mr. Brandt's rebuttal testimony.

a. Refer to page 24, lines 10-20. Please provide the information requested in STF 1.59 and 1.60 (all runs) assuming an equity infusion from PNW into APS on the date and in the amount that Mr. Brandt and the other APS executive management believe it is most likely to occur.

b. Would PNW make the Commission-authorized equity infusion into APS in 2009 if PNW's stock price is below book value? If not, explain fully why not. If so, explain fully why the infusion would be made under those conditions.

c. Would PNW make the Commission-authorized equity infusion into APS in 2009 if (1) no interim rate increase has been granted, and (2) APS' permanent rates have not gone into effect by October 31, 2009? If not, explain fully why not.

d. Refer to page 25, lines 3-12. Please identify each statement in each credit rating agency report which requires an interim rate increase to be granted in 2008 in order to avoid a downgrade.

e. Refer to page 32, line 20-21. When did the "abysmal stock performance" begin?

f. Refer to page 37, lines 22-23, and page 42, lines 3-9. Please quantify, in terms of an annual revenue requirement impact, the "rate decrease that most customer will experience in the November transition to winter rates."

g. How does the amount in part f, compare with the $115 million requested by APS? Please identify, quantify and explain.

h. Refer to page 39. (1) Please explain fully Mr. Brandt's understanding of the income statement results of the Company's own attrition study. (2) Does Mr. Brandt find the income statement portion of the APS attrition analysis to be invalid? If not, explain fully why not.

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS TO
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E-01345A-08-0172
SEPTEMBER 9, 2008

Staff Interim 10.3

Question Continued:

i. Refer to page 39. Please explain why Mr. Brandt included only an expense increase without considering other income statement impacts.

j. Refer to page 40, line 4. Provide all credit rating agency reports which identify an "18% threshold of 'junk'".

k. Refer to page 40, footnote 1. If making the Commission authorized equity infusion as soon as possible would help keep the Company's financial metrics above the "junk" level claimed by Mr. Brandt, would the company and its parent, PNW, not make such an equity infusion while hoping for higher PNW stock prices to occur sometime in 2009? If not, explain fully why not.

l. Refer to page 41, lines 5-7. If the Company's permanent rate increase were made effective November 1, 2009, when the switch to winter rates occurs, wouldn't that help customers by putting a rate increase into effect "at at time when customers are likely to be impacted by a rate increase the least"? If not, explain fully why not.

m. Refer to page 42, lines 17-26 and page 43. (1) Please identify all dates in 2008 and 2009 when PNW could issue up to $400 million of equity that would be permitted under SEC disclosure rules and which are not either market holidays, significant Federal Reserve Bank actions, quarter-end or year-end periods, and the like. (2) For each period identified in part (1), please state PNW/APS executive management's best estimate as to (i) the PNW stock price, and (ii) whether the PNW stock price on such date will exceed the book value.

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS TO
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REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
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E-01345A-08-0172
SEPTEMBER 9, 2008

Staff Interim 10.3

Question Continued:

n. Refer to page 43. (1) Please identify all dates in 2008 and 2009 when PNW/APS executive management thinks it can realistically issue up to $400 million of equity. (2) For each period identified in part (1), please state PNW/APS executive management's best estimate as to (i) the PNW stock price, and (ii) whether the PNW stock price on such date will exceed the book value.

o. Please provide all projections APS and PNW have of the PNW stock price for 2008 and 2009, and show specifically when the PNW stock price is expected to exceed the book value, and why it would be expected by APS/PNW executive management to exceed the book value at that point in time.

p. Refer to page 44. Please identify when in 2008 and 2009 APS/PNW executive management expect the equity market to become un-depressed. If different for (1) electric utilities and (2) for all industries as a group, please state your separate expectations for each group.

q. Has PNW or APS management received any advice from Merrill Lynch or any other investment firm about when in the remainder of 2008 or in 2009 it would be the best time for PNW to issue equity securities? If so, please identify and provide all such advice.

r. Refer to page 47. How much equity "up to $400 million" does PNW executive management expect to issue, and when does PNW expect to issue it?

s. Refer to page 47, line 7. Provide all quantitative information concerning the $40 million increased cost to customers annually.

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS TO
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E-01345A-08-0172
SEPTEMBER 9, 2008

Staff Interim 10.3

Question Continued:

t. Refer to page 47, lines 8-10. When did APS and PNW executive management first conclude that "any equity issuance that Pinnacle West might be able to make would almost certainly be on unreasonable terms, thus increasing capital costs further."

u. When did APS and PNW executive management first conclude that the equity market is depressed?

v. Does APS and PNW executive management foresee any events happening in the remainder of 2008 or in 2009 that would make the equity market more favorable for issuing PNW stock? If so, please explain fully what those events are. If not, explain fully why not

Supplemental Response:

APS previously objected to this question; however, after clarification from Mr. Smith please find APS's supplemental response.

h. Mr. Brandt's calculations on page 39 build on Mr. Smith's recommendation to cover in the interim increase, revenue requirements on increases in rate base since the prior September 30, 2005 test year. Mr. Brandt shows how Mr. Smith's figures would increase to cover book depreciation on the plant additions through 12/31/2007, as well as increases in rate base and book depreciation through 12/31/2008 and 12/31/2009. Mr. Brandt believes Mr. Kearns' operating income and rate base portions of the attrition analysis to be valid.

i. Mr. Brandt's calculations on page 39 were not trying to capture the entire attrition analysis, but merely building on Mr. Smith's proposal for interim relief.

Witness: Donald Brandt

David Rumolo
Manager
Regulation & Pricing

Tel. 602-250-3933
Fax 602-250-3003
e-mail David.Rumolo@aps.com

Mail Station 9708
PO Box 53999
Phoenix, Arizona 85072-3999

September 12, 2008

Maureen A. Scott
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

RE: STAFF'S TENTH SET OF DATA REQUESTS IN THE 2008 INTERIM RATE CASE MATTER
DOCKET NO. E-01345A-08-0172

Dear Ms. Scott,

Enclosed is Arizona Public Service Company's ("APS's") response to Staff's Tenth Set of Data Requests regarding the interim rate case with the exception of 10.1 which is forthcoming. Please note the Company's objections to some of the questions asked therein.

If you or your staff have any questions regarding the enclosed information, please contact me at (602) 250-3933.

Sincerely,

David Rumolo

Attachments

DR/dk

CC: Connie Fitzsimmons
Ralph Smith
Parties of Record

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
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E-01345A-08-0172
SEPTEMBER 9, 2008

Staff Interim 10.2 Refer to the rebuttal testimony of Donald Brandt.

a. Refer to page 4, lines 1-4. Please provide all documents and analysis that prove that the Company's alleged sub-par financial performance, and not any other factors, caused Pinnacle West's stock to fall below book value.

b. Please explain how the effect of regulatory lag on APS is different from other Arizona utilities.

c. Refer to page 9, line 16. Provide a copy of the referenced article.

d. Refer to page 13, lines 9-14. Please provide the documents relied upon for Mr. Brandt's conclusion about each state that he claims uses a future test year.

e. Refer to page 13, line 22. Provide the documents relied upon for the statements concerning Connecticut.

f. Refer to page 13, lines 24-26. Provide the documents relied upon for the statements concerning Delaware.

g. Refer to page 14, line 1-2. Provide the documents relied upon for the statements concerning Mississippi.

h. Refer to page 14, lines 3-6. Provide the documents relied upon for the statement concerning the interim rate procedures of each state listed on lines 5-6.

i. Refer to page 14, lines 7-9. Provide the documents relied upon for the statement concerning the interim rate procedures of each state listed on lines 7-9.

j. Refer to page 14, lines 10-19. Provide the documents relied upon for the statements concerning the Alabama mechanism and how it operates.

k. Refer to page 14, lines 19-23. Provide the documents relied upon for the statements concerning each mechanism used in each state mentioned on those lines.

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS TO
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REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
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E-01345A-08-0172
SEPTEMBER 9, 2008

Staff Interim 10.2

Question Continued:

l. Please identify and explain all distinctions between an "earnings sharing" mechanism and "attrition."

m. Refer to page 17, line 6. Please identify each "Commission-endorsed" program that APS will not be able to fund without an interim rate increase.

n. Refer to page 17, line 7. Please identify each "customer-beneficial" program that APS will not be able to fund without an interim rate increase.

o. Please identify, quantify and explain all capital expenditure programs that have been sacrificed by APS since December 31, 2005.

p. Please identify, quantify and explain all capital expenditure programs that will be sacrificed by APS if an interim rate increase is not granted in the current proceeding.

q. Please identify, quantify and explain all capital expenditure programs that will be sacrificed by APS if an interim rate increase is not granted in the current proceeding until APS receives the equity infusion of up to $400 million from PNW.

r. Refer to the statements on page 17-18 concerning Rocky Mountain Power. What type of test year was used for Rocky Mountain Power?

s. Refer to page 18, lines 7-9. (1) Provide the contract with Abengoa. (2) Identify the specific provisions within that contract that specify the financial condition that APS must be in. (3) Provide the company's construction schedule for the Solana project. (4) Identify all expenditures to date on the Solana project. (5) If APS is not downgraded during its general rate case, what affect on the project schedule would granting no interim increase have?

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS TO
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E-01345A-08-0172
SEPTEMBER 9, 2008

Staff Interim 10.2

Question Continued:

t. Refer to page 19, lines 16 and other statements about the PNW stock price performance. Please identify, quantify and explain how APS and its consultants isolated the various factors, including but not limited to, the impact of the sub-prime mortgage crisis, on the PNW stock price.

u. In view of the PNW stock selling for below book value, has management and/or the board of directors solicited any buy-out offers to help infuse equity into the business? If not, explain fully why not.

v. Refer to page 22, lines 14-15. Provide all credit rating agency documents which require that "the Company still must have an FFO/Debt ratio in the range of 18% to 20% in order to avoid a downgrade to junk."

w. Refer to page 22, lines 14-15. Provide all documents from any source which require that "the Company still must have an FFO/Debt ratio in the range of 18% to 20% in order to avoid a downgrade to junk."

x. Refer to page 26, lines 18-21. Identify all statements in reports requiring "that APS maintain an FFO/Debt ratio within at least the 18-20% range to stay within its current investment grade."

y. Refer to page 26, lines 18-21. Identify all statements not in reports (e.g., from discussion with analysts) requiring "that APS maintain an FFO/Debt ratio within at least the 18-20% range to stay within its current investment grade." For each statement from an analyst that is not in a report, identify the analyst name, the date of the statement and all related documentation APS maintained of the statement. Provide a copy of all such documentation.

z. Refer to page 24, lines 1-9. How does Mr. Brandt propose that the level of permanent rate increase recommendations from Staff, RUCO and/or the other parties can be known by the Commission within the time frame specified for addressing APS' interim rate increase request? Explain fully.

Response:

a. Because APS comprises nearly 95% of Pinnacle West's total assets, there is little question that the Company's performance is the primary driver of Pinnacle West's stock price.

b. As the largest utility in Arizona, APS has larger capital expenditures, greater overall expenses, and is challenged by faster growth than other major Arizona utilities – all factors which make the financial impact of regulatory lag comparatively more challenging. In addition, the mere length of regulatory lag for APS is decidedly longer than it is for SRP, the second largest Arizona utility, which ordinarily receives approval of its requested rate increases within two months (compared to 18 to 24 months for APS), another factor that increases the impact.

c. This article can be obtained electronically at www.azcentral.com.

d. All of the documents relied upon for such statements were obtained from APS's internal research using publicly available resources. An index of the specific authority relied upon for all of the statements regarding regulatory mechanisms used in other states is attached hereto at APS12872.

e. See response to 10.2(d).

f. See response to 10.2(d).

g. See response to 10.2(d).

h. See response to 10.2(d).

i. See response to 10.2(d).

j. See response to 10.2(d).

k. See response to 10.2(d).

l. An "earnings sharing" mechanism attempts to cure the effects of attrition by evaluating financial performance that has already occurred. An "attrition" mechanism attempts to cure the effects of attrition in advance.

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS TO
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E-01345A-08-0172
SEPTEMBER 9, 2008

Staff Interim 10.2

Response Continued:

m. APS objects to this question as misstating Mr. Brandt's testimony. Moreover, APS cannot identify programs that the Commission may endorse in the future.

n. APS objects to this question as misstating Mr. Brandt's testimony. Moreover, APS cannot identify each "customer-beneficial" program that may be available in the future.

o. APS objects to this question as misstating Mr. Brandt's testimony. For a discussion of the Company's historical capital expenditure reductions, see APS's response to Staff 2.25(f).

p. APS objects to this question as misstating Mr. Brandt's testimony. Moreover, APS cannot now identify all capital programs that may exist in the future and/or that may be cut in the future.

q. See response to 10.2(p). The question is also vague and ambiguous to the extent that it attempts to connect two unrelated matters: the grant of interim relief and an equity infusion by Pinnacle West into APS.

r. Refer to www.Pacificorp.com for information related to Rocky Mountain Power.

s. See Commission Docket No. E-01345A-08-0106 for relevant materials that respond to this request.

t. Mr. Brandt's testimony addresses Pinnacle West's stock performance in a relative sense, not in an absolute sense.

u. No. A buy-out would not resolve any of the issues presented in the Company's request.

v. See responses to Staff 2.22.

w. See response to (v) above.

x. See response to (v) above.

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS TO
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E-01345A-08-0172
SEPTEMBER 9, 2008

Staff Interim 10.2

Response Continued:

y. The statement made on the referenced line number is not based on any single statement but on consistent, general discussions with credit rating analysts that have taken place over a period of years. Names of credit rating analysts involved in one or more of such conversations would have included:

- Laura Schumacher – Moody's
- Anne Selting – Standard & Poor's
- Richard Cortright – Standard & Poor's
- Phil Smyth – Fitch

Two recent examples of such discussions are provided in Mr. Brandt's Rebuttal Testimony at pages 26 and 27.

z. Mr. Brandt does not propose any such thing. That was the point.

Witness: Donald Brandt

APS Internal Research: State Regulatory Issues

State	Research	Website Link	Authority
Alabama	Future Test Period	http://www.psc.state.al.us/	By Commission Order, Alabama Public Service Commission Order in Dockets 18117 and 18416 dated 10/4/05 approving Rate RSE
Arkansas	Future Test Period	http://www.arkleg.state.ar.us/ http://www.apscservices.info/	By law, Code of Arkansas §23-4-406 and Rules of Practice and Procedure 3.16(j)
California	Future Test Period	http://www.cpuc.ca.gov/puc/	By Commission Order, California Public Utilities Commission PGE 2007 rate case Docket No. 05-12-002 Decision 07-03-044 dated March 15, 2007
Delaware	Future Test Period	http://regulations.delaware.gov/	By rule, Title 26 Delaware Administrative Code §1002 Part A 1.2 and 1.3
Florida	Future Test Period	https://www.flrules.org/ http://www.psc.state.fl.us/	By rule, Florida Administrative Code 25-6.140, By Commission Order, Order PSC-02-0787-FOF-EI and as filed by Tampa Electric in Docket D-080317-EI 8/11/2008
Georgia	Future Test Period	http://www.lexis-nexis.com/hottopics/gacode/default.asp	By law, Original Code of Georgia Annotated § 46-2-26.1
Hawaii	Future Test Period	http://hawaii.gov/	By rule, Hawaii Administrative Code H.A.C. 6-61-87
Idaho	Future Test Period	Http://www.puc.state.id.us	By Commission Order, Idaho Public Utility Commission Case No. IPC-E-07-08, Order No. 30508 dated 2/28/08
Illinois	Future Test Period	http://www.ilga.gov/commission/jcar/admincode/titles.html	By Rule, Joint Committee on Administrative Rule (JCAR) Administrative Code Title 83: Chapter 1: Subchapter b: Section 287.20 Test Year Options.
Maryland	Future Test Period	http://www.psc.state.md.us/psc/	By Commission Order, Public Service Commission of Maryland Case No. 9036, Order No. 80460 dated 12/21/2005
Minnesota	Future Test Period	https://www.revisor.leg.state.mn.us/pubs/	By rule, Minnesota Administrative Rule (MAR) 7825.4000, 4100, By law Minnesota Statute 216B.16
Mississippi	Future Test Period	http://www.michie.com/mississippi	By law, Mississippi Annotated Code (MAC) 77-3-37(2)(e)
New Jersey	Future Test Period	http://www.bpu.state.nj.us/	By Commission Decision and Order, Board of Public Utilities (BPU) Docket no. ER 06060483 dated 3/22/07 and ER 02050303 dated 7/9/2003
New York	Future Test Period	http://www.dps.state.ny.us/	By Commission Order, New York Public Utilities Commission Cases 07-E-0523 dated 3/25/2008, 04-E-0572 dated 3/24/2005

APS Internal Research: State Regulatory Issues

State	Research	Website Link	Authority
North Dakota	Future Test Period	http://www.legis.nd.gov/	By law, North Dakota Century Code 49-05-04.1
Pennsylvania	Future Test Period	http://www.pacode.com/	By Rule, 52 Pennsylvania Code § 53.56
Wisconsin	Future Test Period	http://psc.wi.gov/	By Commission Order, Decision 6690-UR-118 Ref#67602 Wisconsin Public Service (WPS 1/11/07) Decision 6690-UR-117 Ref#46790 (WPS 12/22/05) Decision 3270-UR-115 Ref#87223 Madison Gas & Electric (MGE 12/14/07)
Connecticut	Interim Rates Triggered by Rate Case	http://www.ct.gov/	By law, 16 Connecticut Statute 277: 16-19(d) By law, 16 Connecticut Statute 277: 16-19(b)
Georgia	Interim Rates Triggered by Rate Case	http://www.legis.state.ga.us	By law, Original Code of Georgia Annotated § 46-2-25.a By law, Original Code of Georgia Annotated § 46-2-25.b
Kansas	Interim Rates Triggered by Rate Case	http://www.kslegislature.org/	By law, Kansas Statutes Annotated 66-117
Kentucky	Interim Rates Triggered by Rate Case	http://www.lrc.state.ky.us	By law, Kentucky Revised Statutes 278.190 By Commission Order, Docket # 2006-00472
Mississippi	Interim Rates Triggered by Rate Case	http://www.michie.com/mississippi	By law, Mississippi Annotated Code 77-3-39
New Hampshire	Interim Rates Triggered by Rate Case	http://www.gencourt.state.nh.us/	By law, New Hampshire Statutes, Chapter 378, Section 378.6 By law, New Hampshire Statutes 378.6III
Oklahoma	Interim Rates Triggered by Rate Case	http://www.oar.state.ok.us/	By rule, Oklahoma Administrative Code 165:70 Subchapter 1
Utah	Interim Rates Triggered by Rate Case	http://le.utah.gov/	By law, Utah Code Section 54-7-12(3)(c) By law, Utah Code Section 54-7-12(3)(a)
Arkansas	General Use Interim Rates	http://www.arkleg.state.ar.us/	By law, Arkansas Code §23-4-408 By law, Arkansas Code §23-4-411
Delaware	General Use Interim Rates	http://delcode.delaware.gov/	By law, 26 Delaware Code §306 (c), Title 26, chapter 1 By law, Delaware Code, title 26, Chapter 1,section 306 a & b
Florida	General Use Interim Rates	http://www.flsenate.gov	By law, Florida Statute 366.071 By law, Florida Statute 366.06
Hawaii	General Use Interim Rates	http://www.capitol.hawaii.gov	By law, Hawaii revised Statute 269-16(c)(d) By rule, Hawaii Administrative Code H.A.C. 6-61-87 By Commission Order No. 22050 in Docket No. 04-0113

State	Research	Website Link	Authority
			dated 9/27/2005
Iowa	General Use Interim Rates	http://www.iowa.gov/ http://www.iowa.gov/iub/	By law, Iowa Code Section 476-6.10 By rule, Iowa Administrative Code - IAC 199-26.8 By Commission Order, Docket No. APP-96-1 and RPU-96-8
Maine	General Use Interim Rates	http://janus.state.me.us/legis/statutes/	By law, Maine Revised Statutes; Title 35-A, Part 1, Chapter 3, § 312 By law, Maine Revised Statutes, Title 35-A, Part 1, Chapter 3, § 310.2
Montana	General Use Interim Rates	http://www.mtrules.org	By statute, Montana Code Annotated (MCA) 69-3-304 By statute, Montana Code Annotated (MCA) 69-3-302 By rule, Administrative Rule of Montana 38.5.501-508
New Jersey	General Use Interim Rates	http://lis.njleg.state.nj.us/	By law, New Jersey Statute 48:2-21.1 By law, New Jersey Statute 48:2-21
North Dakota	General Use Interim Rates	http://www.nd.gov/ http://www.psc.state.nd.us/	By law, North Dakota Century Code 49.05-06 By Commission Order, Case PU-07-776 dated 1/30/2008
Oregon	General Use Interim Rates	http://www.leg.state.or.us	By law, Oregon Revised Statues (ORS) 757-215(5)
Rhode Island	General Use Interim Rates	http://www.helplinelaw.com/usa-statutes/	By law, 39 Rhode island Statutes § 39-3-12 By law, 39 Rhode Island Statutes § 39-3-11
Texas	General Use Interim Rates	http://tlo2.tlc.state.tx.us/statutes/ut.toc.htm	By law, Texas Utilities Code, Chapter 36.108, 36.109 and 36.110
Virginia	General Use Interim Rates	http://leg1.state.va.us/	By rule, 20 Virginia Administrative Code 5-200-30 (b) and (c). Rules governing utility rate increase applications and annual informational filings
Alabama	Attrition, Earnings Sharing, Indexed Adjustment Mechanisms	http://www.psc.state.al.us/	By Commission Order, Alabama Power Rate RSE, approved in APSC Dockets 18117 and 18416 dated 10/4/05, effective 10/16/05
California	Attrition, Earnings Sharing, Indexed Adjustment Mechanisms	http://www.cpuc.ca.gov/puc/	By Commission Order, California Public Utilities Commission Decision 07-03-044 dated March 15, 2007 in Application 05-12-002 for PGE Decision 08-07-046 dated July 31, 2008 in Application 06-12-009 for SDG&E
Georgia	Attrition, Earnings Sharing,	http://www.psc.state.ga.us/	By Commission Order, Georgia Public Service

APS Internal Research: State Regulatory Issues

State	Research	Website Link	Authority
	Indexed Adjustment Mechanisms		Commission Order in Docket No. 25060-U Document 108457 dated 12/18/07
Iowa	Attrition, Earnings Sharing, Indexed Adjustment Mechanisms	http://www.iowa.gov/iub/	By Commission Order, Iowa Utilities Board Docket No. RPU-07-02 dated 7/27/07 Docket No. RPU-01-3, and RPU-01-5 dated 12/21/01
Louisiana	Attrition, Earnings Sharing, Indexed Adjustment Mechanisms	http://www.entergy-louisiana.com/	By Commission Order, Entergy Louisiana Formula Rate Plan Rider Schedule FRP-4, effective 1/31/06
Maine	Attrition, Earnings Sharing, Indexed Adjustment Mechanisms	http://www.maine.gov/mpuc/	By Commission Order, Maine Public Utilities Commission Docket No. 2007-215, 2008-111 dated 7/1/08
Massachusetts	Attrition, Earnings Sharing, Indexed Adjustment Mechanisms	http://www.state.ma.us/dpu/	By Commission Order, Department of Public Utilities Docket DTE 05-85 dated 12/30/05
Mississippi	Attrition, Earnings Sharing, Indexed Adjustment Mechanisms	http://www.entergy-mississippi.com/	By Commission Order, Entergy Mississippi Formula Rate Plan Rider Schedule FRP-4 effective 12/31/02
North Dakota	Attrition, Earnings Sharing, Indexed Adjustment Mechanisms	http://www.psc.state.nd.us/	By Commission Order, NDPSC Order Adopting Settlement in Case No. PU-06-525 dated 6/13/07
Oklahoma	Attrition, Earnings Sharing, Indexed Adjustment Mechanisms	http://www.occ.state.ok.us/	By Commission Order, OCC Cause No. PUD 200400187, Order No. 499253 dated 12/28/04
Vermont	Attrition, Earnings Sharing, Indexed Adjustment Mechanisms	http://www.state.vt.us/psb/	By Commission Order, Vermont Public Service Board Order in Docket Nos. 7175 and 7176 dated 12/22/06

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
SEPTEMBER 9, 2008

Staff Interim 10.3 Refer to Mr. Brandt's rebuttal testimony.

a. Refer to page 24, lines 10-20. Please provide the information requested in STF 1.59 and 1.60 (all runs) assuming an equity infusion from PNW into APS on the date and in the amount that Mr. Brandt and the other APS executive management believe it is most likely to occur.

b. Would PNW make the Commission-authorized equity infusion into APS in 2009 if PNW's stock price is below book value? If not, explain fully why not. If so, explain fully why the infusion would be made under those conditions.

c. Would PNW make the Commission-authorized equity infusion into APS in 2009 if (1) no interim rate increase has been granted, and (2) APS' permanent rates have not gone into effect by October 31, 2009? If not, explain fully why not.

d. Refer to page 25, lines 3-12. Please identify each statement in each credit rating agency report which requires an interim rate increase to be granted in 2008 in order to avoid a downgrade.

e. Refer to page 32, line 20-21. When did the "abysmal stock performance" begin?

f. Refer to page 37, lines 22-23, and page 42, lines 3-9. Please quantify, in terms of an annual revenue requirement impact, the "rate decrease that most customer will experience in the November transition to winter rates."

g. How does the amount in part f, compare with the $115 million requested by APS? Please identify, quantify and explain.

h. Refer to page 39. (1) Please explain fully Mr. Brandt's understanding of the income statement results of the Company's own attrition study. (2) Does Mr. Brandt find the income statement portion of the APS attrition analysis to be invalid? If not, explain fully why not.

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
SEPTEMBER 9, 2008

Staff Interim 10.3

Question Continued:

i. Refer to page 39. Please explain why Mr. Brandt included only an expense increase without considering other income statement impacts.

j. Refer to page 40, line 4. Provide all credit rating agency reports which identify an "18% threshold of 'junk'".

k. Refer to page 40, footnote 1. If making the Commission authorized equity infusion as soon as possible would help keep the Company's financial metrics above the "junk" level claimed by Mr. Brandt, would the company and its parent, PNW, not make such an equity infusion while hoping for higher PNW stock prices to occur sometime in 2009? If not, explain fully why not.

l. Refer to page 41, lines 5-7. If the Company's permanent rate increase were made effective November 1, 2009, when the switch to winter rates occurs, wouldn't that help customers by putting a rate increase into effect "at at time when customers are likely to be impacted by a rate increase the least"? If not, explain fully why not.

m. Refer to page 42, lines 17-26 and page 43. (1) Please identify all dates in 2008 and 2009 when PNW could issue up to $400 million of equity that would be permitted under SEC disclosure rules and which are not either market holidays, significant Federal Reserve Bank actions, quarter-end or year-end periods, and the like. (2) For each period identified in part (1), please state PNW/APS executive management's best estimate as to (i) the PNW stock price, and (ii) whether the PNW stock price on such date will exceed the book value.

Staff Interim 10.3

Question Continued:

n. Refer to page 43. (1) Please identify all dates in 2008 and 2009 when PNW/APS executive management thinks it can realistically issue up to $400 million of equity. (2) For each period identified in part (1), please state PNW/APS executive management's best estimate as to (i) the PNW stock price, and (ii) whether the PNW stock price on such date will exceed the book value.

o. Please provide all projections APS and PNW have of the PNW stock price for 2008 and 2009, and show specifically when the PNW stock price is expected to exceed the book value, and why it would be expected by APS/PNW executive management to exceed the book value at that point in time.

p. Refer to page 44. Please identify when in 2008 and 2009 APS/PNW executive management expect the equity market to become un-depressed. If different for (1) electric utilities and (2) for all industries as a group, please state your separate expectations for each group.

q. Has PNW or APS management received any advice from Merrill Lynch or any other investment firm about when in the remainder of 2008 or in 2009 it would be the best time for PNW to issue equity securities? If so, please identify and provide all such advice.

r. Refer to page 47. How much equity "up to $400 million" does PNW executive management expect to issue, and when does PNW expect to issue it?

s. Refer to page 47, line 7. Provide all quantitative information concerning the $40 million increased cost to customers annually.

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
SEPTEMBER 9, 2008

Staff Interim 10.3

Question Continued:

t. Refer to page 47, lines 8-10. When did APS and PNW executive management first conclude that "any equity issuance that Pinnacle West might be able to make would almost certainly be on unreasonable terms, thus increasing capital costs further."

u. When did APS and PNW executive management first conclude that the equity market is depressed?

v. Does APS and PNW executive management foresee any events happening in the remainder of 2008 or in 2009 that would make the equity market more favorable for issuing PNW stock? If so, please explain fully what those events are. If not, explain fully why not

Response:

a. APS assumes this request refers to Staff 2.59 and Staff 2.60. Neither Mr. Brandt nor other executive management can speculate as to when the equity infusion is most likely to occur. See response to Staff 4.3(a).

b. It depends on the circumstances.

c. See response to 10.3(b).

d. APS objects to this question as misstating Mr. Brandt's testimony. For a response that accurately characterizes Mr. Brandt's testimony, refer to Mr. Brandt's Rebuttal Testimony at page 25, lines 3-23.

e. See the graphs depicted on pages 34 and 35 of Donald Brandt's Direct Testimony in the general rate case, and that shown on page 46 of his Rebuttal Testimony in the interim matter.

f. APS objects to this question as vague. However, the proof of revenue calculations found in the rate case workpaper, GAD_WP3, are performed based on seasonal rates.

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
SEPTEMBER 9, 2008

Staff Interim 10.3

Response Continued:

g. See response to 10.3(f).

h. APS objects to this question as vague and ambiguous.

i. APS objects to this question as vague and ambiguous.

j. See response to 10.2 (v).

k. No. The issuance and the infusion are necessarily tied, as Pinnacle West lacks the funds to infuse into APS without the equity issuance.

l. Yes, though doing so all at once in 2009 would deprive the Commission of the opportunity to phase-in the rate relief granted in the general rate case (thus minimizing the bill impact on customers) and would deprive the Company of justified financial relief.

m. (1) Such dates depend upon the facts and circumstances that exist at the time. See Mr. Brandt's rebuttal testimony at page 42-43 for a discussion of periods during which the market is generally inaccessible. (2) APS is unable to speculate as to the value of the PNW stock price at any future point in time.

n. See responses to 10.3(a) and 10.3 (m)(2).

o. See response to (m)(2) above.

p. APS cannot speculate as to when the market may become "un-depressed."

q. No.

r. See response to 10.3(a).

Staff Interim 10.3

Response Continued:

s. See the attached spreadsheet, APS13458.

t. Although not "first" made at any single point in time, the conclusion generally occurred over a period in mid-2008.

u. Although a conclusion regarding market conditions was not "first" made at any single point in time, APS was generally aware of depressed market conditions in 2007 and 2008.

v. Executive management does not have the ability to predict future events that would make the equity market more favorable for stock issuances.

Witness: Donald Brandt

Change in Revenue Requirements from Incremental $400m of Equity vs. Debt Financing ($m)

ACC adjusted rate base in this case	5,360
Return on equity	10.75%
Assumed interest rate on incremental debt	7.00%
	60%
Assumed interest rate on incremental debt after tax	4.20%
Difference in after tax cost of equity vs debt	6.55%
Revenue conversion factor	1.6491
Difference in cost of equity vs debt at the revenue requirement level	10.80%
Financing that the change applies to	400
Change in revenue requirement from incrementally financing $400m with equity instead of debt	43

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
SEPTEMBER 9, 2008

Staff Interim 10.4 Refer to Mr. Brandt's Attachment DEB-RB-2, page 2 of 19. (a) Please state fully APS' understanding of the paths which "are more likely than others to produce lower cost electricity." (b) Is APS following the lower cost electricity paths identified in response to part a? If so, explain fully how. If not, explain fully why not. (c) Does APS agree with everything in Attachment DEB-RB-2? If not, please identify each statement in Attachment DEB-RB-2 with which APS does not agree.

Response: (a)-(b). The referenced statements are from Chairman Kelliher, not APS. APS does not know what specific meaning Chairman Kelliher intended in the quote referenced in the question. (c) APS intended Attachment DEB-RB-4 to give context to the Company's challenges and be otherwise informative and helpful. It has not formed an opinion on every specific item discussed in the attachment.

Witness: Donald Brandt

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
SEPTEMBER 9, 2008

Staff Interim 10.5	Refer to Attachment DEB-RB-4, page 2. (a) During 2008 which of the items listed on page 2 of Attachment DEB-RB-4 has APS not undertaken as cost reduction measures and why. (b) Does APS disagree with any of the items listed on page 2 of Attachment DEB-RB-4 as items that APS could also undertake to help keep electric prices low in Arizona? If so, please identify each item and explain why APS disagrees with it. If not, explain fully why not.
Response:	(a) APS has not implemented any of the referenced measures. Under the facts and circumstances, APS does not believe that taking any of these measures would be advantageous to customers, nor would doing so necessarily lower electric prices. (b) Yes. See response to 10.5(a) and Mr. Brandt's Rebuttal Testimony at pages 17-18.

Witness: Donald Brandt

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
SEPTEMBER 9, 2008

Staff Interim 10.6 Refer to Dr. Cicchetti's rebuttal at page 5, lines 18-19. (a) Please state in detail the witness' specific knowledge of the "degree of regulatory lag" that is "present in most jurisdictions." (b) Please identify, and provide a copy of, the documents relied upon for the answer to part a.

Response:

(a) Dr. Cicchetti has not done a formal study or conducted detailed research of the "degree of regulatory lag" that is present in any particular jurisdiction. Instead, he relies on his more than 40 years of related industry experience.

(b) Not applicable.

Witness: Charles Cicchetti

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
SEPTEMBER 9, 2008

Staff Interim 10.7 Refer to Dr. Cicchetti's rebuttal at page 5, lines 21-22. (a) Please explain fully the witness' understanding of why the regulatory lag in Arizona has not been mitigated by other ratemaking practices, including attrition adjustments and interim rates. (b) Explain in detail what at "make whole" proceeding is.

Response:

(a) Dr. Cicchetti bases his understanding on discussions with APS and his reading of various financial analysts' discussions of regulation in Arizona.

(b) Dr. Cicchetti uses the term "make whole proceeding" to describe a regulatory proceeding in which regulation, either at the conclusion of a rate proceeding or subsequent to new rates going into effect, takes into account known changes typically outside the utility's control that make it impossible for the utility to have a reasonable opportunity to earn its authorized Rate of Return. To some extent, make whole and attrition allowances are synonymous.

Witness: Charles Cicchetti

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
SEPTEMBER 9, 2008

Staff Interim 10.8

Refer to Dr. Cicchetti's rebuttal at page 7, lines 16-19: "I would expect rating agencies, including S&P, Moody's and Fitch, to either downgrade APS or at least raise enough questions to increase the cost of capital for APS and its customers." (a) Please identify all prior testimonies of Dr. Cicchetti wherein he predicted a credit rating downgrade if the utility did not receive the full amount of rate increase it was requesting. (b) Has Dr. Cicchetti ever presented testimony in any other regulatory proceeding wherein he predicted a credit rating downgrade if the utility did not receive the full amount of rate increase it was requesting? If so, please identify all such testimony. (c) Please provide a complete copy of the testimony identified in response to part b. (d) Does Dr. Cicchetti have any specific knowledge of any situations where he predicted a credit rating downgrade if the utility on whose behalf he was testifying did not receive the full amount of rate increase it was requesting? If not, explain fully why not. If so, please state fully all of Dr. Cicchetti's knowledge in this regard.

Response:

(a) Dr. Cicchetti has never predicted a downgrade. He has only raised the possibility of a credit rating downgrade, which would possibly occur, other things equal, when regulators fail to provide an opportunity for a specific utility to earn a just and reasonable return.

(b) Dr. Cicchetti has never presented testimony where he predicted a downgrade. He has only raised the possibility of a credit rating downgrade, other things equal, if regulators fail to provide an opportunity for a specific utility to earn a just and reasonable return.

(c) Not applicable.

(d) Not applicable. Dr. Cicchetti has never predicted a downgrade. See responses to (a) and (b) above.

Witness: Charles Cicchetti

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
SEPTEMBER 9, 2008

Staff Interim 10.9 Refer to Dr. Cicchetti's rebuttal at page 7, lines 16-19: "I would expect rating agencies, including S&P, Moody's and Fitch, to either downgrade APS or at least raise enough questions to increase the cost of capital for APS and its customers." Please provide all information in Dr. Cicchetti's possession concerning his prior predictions of utility credit rating downgrades if a utility did not receive the full amount of rate increase it was requesting.

Response: Dr. Cicchetti never predicted a downgrade. He has, in prior testimonies, raised questions, like he has here, about the possible effects of negative analysts' opinions and the negative repercussions if these, with some probability, led to a downgrade.

Witness: Charles Cicchetti

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
SEPTEMBER 9, 2008

Staff Interim 10.10 (a) Has Dr. Cicchetti ever testified on behalf of a utility in support of a rate increase in a case where the utility's regulatory commission granted a lower amount than was requested by the utility? If so, please identify all instances. (b) In each instance identified in response to part a, please explain in detail Dr. Cicchetti's understanding of why the respective regulatory commission granted a lower amount of rate increase to the utility than he was recommending. (c) Does Dr. Cicchetti have any specific knowledge of the resultant impact on the utility's credit rating in each instance identified in response to part a? If not, explain fully why not. If so, please state fully Dr. Cicchetti's specific knowledge with regard to each such instance. (d) Please provide all documents relied upon for your answers to parts a, b and c.

Response:

(a) Yes. As a factual matter, Dr. Cicchetti cannot recall any situation in which a regulatory commission granted more than or equal to what the utility requested. However, Dr. Cicchetti typically does not keep copies of orders in the rate cases in which he has presented testimony, which are nevertheless available typically in the public record. That said: the following is a list of the proceedings in which Dr. Cicchetti, to the best of his recollection, submitted testimony in support of a utility's requested rate of return or return on equity.

- **Connecticut Natural Gas Corporation:** Before the Connecticut Public Utility Control Authority (July 1981).
- **Arkansas Louisiana Gas Company:** Testimony before FERC on rate of return, theory, risk and capital structure (February 1983).
- **Arkansas Louisiana Gas Company:** Testimony before the Arkansas Public Service Commission (August 1983).
- **Florida Power and Light Company:** Testimony before FERC February 1984).
- **Consolidated Gas Supply Corporation:** Testimony before FERC on rate of return and capital structure (April 1984).
- **Ohio Power Company:** Testimony before the Public Utilities Commission of Ohio (July 1985).
- **Ohio Power Company:** Testimony before the Public Utilities Commission of Ohio (April 1986).

Staff Interim 10.10

Response Continued:

- **Kansas Gas & Electric Company:** Testimony before the Kansas Corporation Commission (June 1995).
- **Western Resources:** Testimony before the Kansas Corporation Commission (March 1996).
- **Pennsylvania Power Company:** Testimony before the Pennsylvania Public Utilities Commission. (September 1997. February 1998).
- **Western Resources:** Testimony before the Kansas Corporation Commission and the Missouri Public Service Commission (June 1998).
- **Georgia Power Company:** Testimony before the Georgia Public Service Corporation (June and October 1998).
- **Western Resources:** Testimony before the Kansas Corporation Commission (April 2000, January 2001, and April 2001).
- **Florida Power Company:** Testimony before the Florida Public Service Commission (September 2001).
- **Puget Sound Energy:** Testimony before Washington Utilities and Transportation Commission (April and November 2004
- **Progress Energy Florida**: Testimony before the Florida Public Service Commission (April and August 2005).

(b) Dr. Cicchetti does not know the specific rationale each Commission used in making its order. Dr. Cicchetti does not have copies of the orders in these cases, which he assumes are in the public record. Dr. Cicchetti has not performed any analysis with respect to any particular Commission's specific rationale for granting the rate increase it granted in any of the cases identified in the previous response.

(c) No. Dr. Cicchetti has seldom, if ever, been hired as a management consultant to analyze the effects of orders in rate cases.

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
SEPTEMBER 9, 2008

Staff Interim 10.10

Response Continued:

(d) Dr. Cicchetti used his resume, which is attached as Exhibit A of his Affidavit in support of the Company's Motion for Interim Rate Relief, to refresh his recollection as to the cases in which he has provided testimony in a rate case.

Witness: Charles Cicchetti

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
SEPTEMBER 9, 2008

Staff Interim 10.11 Refer to Dr. Cicchetti's rebuttal at page 13, lines 12-16: "The financial analysts and rating agencies have granted APS a bit of a reprieve, but they are poised to act to downgrade APS' bonds if they see signs that the Commission does not appreciate APS' financial problems due to inadequate cash flow, significant new investments, and an regulatory lag that does not and cannot make APS whole." (a) Provide all documents relied upon by Dr. Cicchetti for this statement. (b) Please specifically identify each financial analyst that is poised to downgrade APS. (c) Please identify each rating agency that is poised to downgrade APS. (d) Provide all documents relied upon for your responses to parts b and c.

Response:

(a) Dr. Cicchetti relied on the documents from Moody's Fitch, and S&P that were attached to the testimony filed by Mr. Parcell as Attachments 5, 6, 8, and 9.

(b) See Response to Staff 10-11(a). Specifically, S&P states "Ratings could be lowered to speculative grade if the company is not able to overcome the challenge of ensuring timely recovery of prudently incurred costs." (June 2008). Additionally, Moody's observed that its "rating and outlook consider the traditionally challenging regulatory environment in Arizona" and was watching for continued evidence that recent ACC decisions and regulatory actions "appear intended to reduce regulatory lag and provide more timely recovery of certain costs." (July 28, 2008).

(c) See response to (b) above.

(d) Mr. Parcell attached these documents to his testimony as Attachments 5, 6, 8, and 9.

Witness: Charles Cicchetti

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
SEPTEMBER 9, 2008

Staff Interim 10.12 Refer to Dr. Cicchetti's rebuttal testimony. Does Dr. Cicchetti have any opinion on whether the Commission's granting APS authority to receive an equity infusion of up to $400 million from its parent PNW was viewed as supportive by any financial analysts or rating agencies? If so, please state fully Dr. Cicchetti's opinion in this regard, and provide all documents relied upon. If not, explain fully why not.

Response: Dr. Cicchetti thinks that infusing $400 million new equity would have some benefit in terms of an increase in cash. However, the not-so-favorable effects would be the dilution effect this would have under current market conditions and the fact that other investor-owned utilities historically and currently are able to finance new investments out of internally generated cash flow from depreciation expense recovery and operating income more broadly. As Dr. Cicchetti explained in his testimony, he is concerned that APS' growth is not producing the type of improvements in its value as a business in the manner most businesses would and do experience. Dr. Cicchetti thus views any need to infuse $400 million (or any similar amount) of new equity as representing the financial weakness of APS, not strength.

Witness: Charles Cicchetti

ARIZONA CORPORATION COMMISSION
STAFF'S TENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
SEPTEMBER 9, 2008

Staff Interim 10.13	To the extent not already provided, please provide Mr. Rumolo's rebuttal exhibits and workpapers electronically in Excel.
Response:	Attached in Excel as APS10775 is David Rumolo's Attachment DJR_RB-1.

Witness: David Rumolo

ARIZONA CORPORATION COMMISSION

EXHIBIT
ALL-STATE LEGAL®
S-8

September 5, 2008

Via E-mail Only

Thomas L. Mumaw
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Re: Staff's Responses to APS' Third Set of Data Requests in Arizona Public Service Company Motion for Approval of Interim Rate and Preliminary Order and General Rate Case; Docket No. E-01345A-08-0172

Dear Messrs Mumaw, Maledon, Metli and Ms. Grabel:

Enclosed are Staff's responses to Arizona Public Service Company's Third Set of Data Requests to the Arizona Corporation Commission Staff in the above-referenced matter.

Please do not hesitate to contact me if you have any questions regarding the attached.

Sincerely,

Amanda Ho
Attorney
Legal Division
(602) 542-3402

AH:klc

Enclosure

ARIZONA PUBLIC SERVICE COMPANY'S
THIRD SET OF DATA REQUESTS TO
ARIZONA CORPORATION COMMISSION
Docket No. E-01345A-08-0172 – Interim Rate Motion
September 5, 2008

Subject: To the extent available, requested information should be provided in searchable PDF, DOC or EXCEL files via email or electronic media.

APS 3.1 The table on Page 10 of the testimony of David Parcell dated August 29, 2008, lists as its source the AUS Utility Reports of July 2007 which are Exhibit 7 to his testimony. The information contained in Exhibit 7, however, does not appear to correspond to the numbers set forth in the table on Page 10 of the Parcell testimony. Accordingly, please provide the following:

1. The name of each of the companies in each "rating" category (i.e., Aaa/AAA through Not Rated) for both rating agencies listed in the table on Page 10 of the Parcell testimony.

2. With respect to the electric-only companies listed in Exhibit 7 to the Parcell testimony, do you agree that no company has an S&P bond rating as low as or lower than PNW?

3. With respect to combination electric and gas companies listed in Exhibit 7 to the Parcell testimony, please identify those companies that have an S&P bond rating as low as or lower than PNW.

RESPONSE: The table on page 10 of Mr. Parcell's testimony cites as its source the July 2007 AUS Utility Reports. The numbers on the table on page 10 are in fact derived from the July 2007 AUS Utility Reports, as cited. The numbers shown on the table are correct for the period stated in the source.

Attachment 7 to Mr. Parcell's testimony (not Exhibit 7 as stated in the Data Request) shows the August 2008 AUS Utility Reports. This is not the source of the table on Page 10. The table on Page 10 should have used the August 2008 AUS Utility Reports. A revised table, similar to that on Page 10 but reflecting the August 2008 AUS Utility Reports data, is shown on the following page.

Rating	Moody's	S&P
Aaa/AAA	1	
Aa1/AA+	1	
Aa2/AA	2	1
Aa3/AA-	2	2
A1/A+	4	1
A2/A	8	8

APS' FIRST SET OF DATA REQUESTS TO
ARIZONA CORPORATION COMMISSION
Docket No. E-01345A-08-0172
August _, 2008

Subject: To the extent available, requested information should be provided in <u>searchable</u> PDF, DOC or EXCEL files via email or electronic media.

A3/A-	12	16
Baa1/BBB+	11	11
Baa2/BBB	**16**	13
Baa3/BBB-	3	**4**
Ba1/BB+	1	1
Not Rated	4	5

As was the case in the table on Page 10 of Mr. Parcell's testimony, the bold numbers reflect APS' current ratings. The conclusions reached by Mr. Parcell on Page 10, lines 15-16, concerning this the information contained in this table remain the same when the August 2008 AUS Utility Reports data is substituted for the July 2007 AUS Utility Reports data. Thus, the updating of the bond ratings data does not impact Mr. Parcell's testimony and conclusions.

The responses to the specific questions posed in the data request are as follows:

1. **The information requested is contained in Attachment 7 to Mr. Parcell's testimony, which is the August 2008 AUS Utilities Reports.**

2. **No, Mr. Parcell does not agree with this. PWC has a S&P bond rating of BBB- Three other companies have a BBB- rating (NiSource, TECO Energy, and Westar) and one has a lower rating (BB+ PNM Resources). One of these (Westar) is listed by AUS Utility Reports as an electric-only company. It is noteworthy that 15 of the companies have a Moody's rating of Baa2 (i.e., APS and PWC rating) and three have a lower rating. Six of these are listed by AUS Utility Reports as electric-only companies.**

3. **Of the combination electric and gas companies, two have the same S&P rating as APS and PWC and one has a lower rating. These companies are identified in the response to 2 above.**

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EXHIBIT
S-9
ADMITTED

February 14, 2008

Bulletin:

Arizona Public Service Rating Supported By Two Arizona Corporation Commission Rulings

Primary Credit Analyst:
Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

SAN FRANCISCO (Standard & Poor's) Feb. 14, 2008--Standard & Poor's Ratings Services said that two rulings issued yesterday by the Arizona Corporation Commission (ACC) are constructive in delivering timely rate relief to Arizona Public Service, or APS (BBB-/Stable/A-3). (APS' parent company is Pinnacle West Capital Corp.)

In separate matters, the ACC approved a change in APS' line extension policies and authorized the flow through to customers of an interim transmission rate increase that was approved by the Federal Energy Regulatory Commission (FERC) in 2007.

The line extension ruling revokes the free footage allowance that APS used to give customers. The change is expected to provide APS with about $50 million in incremental pre-tax cash in 2008 to offset some of the company's distribution investment. Due to the rolloff of grandfather provisions, this amount will approximately double in 2009. While the ACC's ruling rejected the revenue accounting treatment sought by APS, it regardless provides the company with an upfront source of cash for its capital program, estimated to be in excess of $1 billion in 2008. (For details, see related article Arizona Public Service Co.'s Proposal To Increase Cash Flow Through Unique Line Extension Policy Change published Feb. 4, 2008, on RatingsDirect.)

Last October, the FERC authorized APS to increase its wholesale and retail transmission rates by approximately $37 million. About $30 million of this increase is associated with retail rates, causing APS to seek ACC approval to flow through this rate increase to customers. The ACC yesterday approved the use of a transmission rate adder created in 2005 to implement the rate increase. Favorably, the ACC will allow collection to begin on March 1, 2008, concurrent with the FERC's authorization. The FERC- and ACC-approved rate increase is an interim one. Amounts could be subject to refund, pending the final outcome of the FERC case, likely at the end of 2008.